STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

BIMONTHLY MEETING
OF THE PUBLIC SERVICE COMMISSION

Thursday, May 15, 2014
9:00 a.m.
19th Floor Board Room
Three Empire State Plaza
Albany, New York 12223-1350

COMMISSIONERS:
Audrey Zibelman, Chair
Diane X. Burman
Patricia L. Acampora
Garry Brown
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(The hearing commenced at 9:00 a.m.)

CHAIR ZIBELMAN: Good morning, everyone. Thank you for joining us. I think today may be our first occasion to use this new process. We're having technical conferences and asking people to come in so that we can do fact finding. And I really appreciate the involvement, the presentations that we've seen. I think they're all going to be posted.

And I want everyone to understand that today we are in the process of gathering information. We will have an opportunity to invite you to write additional comments and thoughts after hearing the presentations today.

And all the presentations are going to be online. Before I begin officially, Secretary Burgess, is there any additional changes to the agenda for today?

SECRETARY BURGESS: There are no changes to the agenda. But, if I may just go over the guidelines for the presentations this morning?

CHAIR ZIBELMAN: Sure.

SECRETARY BURGESS: Just so you
know, some guidelines that we have in place because the presenters are going to be providing a wealth of information, so we want to make sure there's adequate time for all the presentations, and also time for the commissioners to ask all their questions.

So with respect to the time limits, the presenters were made aware of the time periods that they have. For our initial panel in background, each of those panels will have about fifteen minutes. The first panel will have six minutes, and then ten minutes for each of -- for each presenter for each of the remaining panels.

I'm going to be using this lighting system. When you're speaking, the green light will be on. When you have one minute left, it will be flashing. And when your time is up, it's going to be very red. And I ask you to please be mindful of that time, just so there is adequate time for all the presenters to present, and so the commissioners do have time to ask their questions.

There will be a dedicated question and answer period, which will be at the end of the panel. Not after each individual speaker. So after all the presenters have finished their presentations,
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then the commissioners -- the chair will begin the conversation, and each of the commissioners will have opportunities to ask questions.

As the chair mentioned, all of the materials are posted now on the website, all these presentations. If you go on the Commission's website under the webcast session schedule and look at today's date, there's a box there where you can click on, and all these materials are available now for you to view as presentations are being -- are going on.

And finally, as the chair mentioned, there is going to be a thirty-day comment period. I'll issue a notice tomorrow, and that will set forth a process for submitting comments on any issues that are discussed today. I just ask you to include the docket number for this case. The matter number is fourteen, dash, zero zero nine three three. That will be included on the notice tomorrow. But please make sure that you include that. Thank you.

CHAIR ZIBELMAN: Thank you.

And if you do go over, there will be electric shocks underneath the table.

Before we begin, first of all, I want to set -- make sure that we are setting the
stage in the right way. This is, for myself and my fellow commissioners, really a fact-finding inquiry. Clearly, last winter's -- this past winter's cold weather, the polar vortex created high prices, responses in the market. One -- and our concern, of course, is -- moving forward, is really two of our major pillars of things that we get concerned about.

One is reliability, trying to understand, if there's a scarcity of infrastructure, where that might lie, and what types of things we need to be doing to change that. And also, in terms of reliability, if there are operating changes that we would ask that the ISOs or generators or others to make that we work with our -- with FERC, and see that those changes are -- are being made.

And on that note, I would want to note my appreciation in advance for -- for FERC Commissioner Cheryl LaFleur has graciously allowed us -- asked our -- answered our request to have Jeffery Dennis join us today from FERC. And we're very appreciative in advance of the work that FERC is doing already to start to address these issues. Today is really the focus on what we should be doing at the state level, what changes we should be making
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as we move forward.

The other piece, of course, of our concern is prices, and price volatility, and its effect on consumers. And that really gets to the heart, which is -- you know, I'm looking forward to hearing from the consumer panel. But really, thinking in terms of what we can do because there's always going to be volatility in this market. That doesn't mean it's a problem. It's the nature of the commodity we're dealing with. But in fact, we need to think about how do we protect consumers who, otherwise, can't protect themselves because of -- in those particular residential and mass market, to make sure that they're appropriately hedged, and to think about what we -- what policies we might put in place going forward to address that type of situation.

Again, I -- one of the things I do want to note, though, that, you know, one of the things that we did see is that despite the polar vortex, and I think you'll be hearing about this today, the system performed. We didn't have blackouts. We didn't have brownouts. The generators did an excellent job. ISO did an excellent job. The transmission owners did an excellent job. That --
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that is important.

But nonetheless, when we see prices like this, these are silent signals. And it's important that we start addressing them and then we begin looking at these collectively. And I -- I would say, without hesitation, based on the people I know who are in this room, and the people in the industry in New York, that everyone here wants to be in a position that we're not having to answer complaints about consumers who are unable to pay their bills.

And that's what really the focus is today, is what we should be doing going forward to better position ourselves because, as we've learned in New York, these weather events are not one-time events, and we need to think about this as our new reality.

So I appreciate, also, that a lot of these issues are about the intersection of gas and electric. And that's -- that's an issue that, I think, the nation is being to deal with, the FERC is dealing with. And I want to congratulate, actually, Garry Brown, who was, early on, advocating for looking at this intersection, and has been hard at
work, and in fact -- helped put this -- organize this agenda to make sure that we can continue to look at these issues, and delve into them in a meaningful way.

So with that, we have all of the bios in the back, and they're also online. So I'm not going to go through and give everybody's introduction, but I can tell you we have a lot of smart people in this room. So I think we're going to figure some things out.

And let me start then, and our first panel is really setting the background. Again, welcome, Jeffery. I really appreciate FERC's participation here, and -- and look forward to hearing what -- what you have to say, and what you're doing.

And then also, Raj Addepalli, as well as some of his team members, Mike Twergo, (phonetic spelling), and Cynthia McCarron will be providing information that the Staff has put together.

So we'll start off with you, Jeffery, and please -- Jeffery is the director of the Division of Policy Development for the FERC.
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MR. DENNIS: Thank you, Chair Zibelman and Commissioners. Good morning.

My name is Jeff Dennis, and I'm director of the Division of Policy Development in FERC's office of Energy Policy and Innovation.

I'll move closer. It's rare I'm unable to be heard.

We appreciate the invitation to help set the stage for your discussions this morning with an overview of regional conditions and impacts from the severe cold weather events experienced last winter. I am presenting FERC staff's preliminary observations and analysis of the operations of the natural gas, and the regional R.T.O. and I.S.O. markets under conditions of severe stress and market pressures.

I'd like to thank staff in FERC's Office of Enforcement, Division of Energy Market Oversight, and Division of Analytics and Surveillance, and FERC's office of Electric Reliability for their work in compiling and analyzing the data and observations in this presentation. This report does not necessarily reflect the view of the Commission or any commissioner.
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The first three months of 2014 were marked by historically cold weather across large swaths of the country, record high natural gas and electric demand, and record high natural gas prices, which translated into abnormally high electricity prices. The cold weather tested the performance of the natural gas and electricity systems, and the functioning of markets, which at times came under severe stress.

Four major cold events occurred in the natural gas and power markets during January and February, followed by a less extensive event in early March. This presentation will largely focus on the impacts of the first three major cold events you see there, which had the most impact in New York, and the surrounding regions.

U.S. daily natural gas demand spiked to record highs in January, coincident with the extreme cold weather events. Widespread low temperatures, high winds, and snow drove U.S. natural gas demand to reach an all-time peak of one hundred and thirty-seven billion cubic feet, or B.C.F., on January 7.

During the later January events,
U.S. natural gas demand topped out at one hundred and thirty-two B.C.F. per day on January 27th, compared to the eighty-six B.C.F. per day five-year average for that date, but did not reach the peak set earlier in the month.

There were two lesser demand spikes in earlier February -- or I'm sorry -- in early February and early March that were well above the five-year range. Overall, U.S. natural gas demand during this period increased eight percent over last year, averaging ninety-six B.C.F. per day, a record for the quarter.

Residential and commercial demand was up fifteen percent. Industrial natural gas demand was up two percent, while power burn fell one point five percent. The notable decline in power burn can be attributed in part to increased reliance on fuel oil generation discussed in greater detail later in this presentation.

Natural gas supply, including strong production from shale resources and imports, averaged seventy-two B.C.F. per day, up three percent from last year. The gap between natural gas supply and demand was filled by storage withdrawals, which
set several records during January and February, and left U.S. natural gas storage depleted at an eleven-year low of eight hundred and ninety-six B.C.F. for the week ending March 21st. For the week ending May 2nd, U.S. natural gas storage had recovered to one thousand fifty-five B.C.F.

The three major cold events that stressed natural gas and power markets during January and early February were spread across a large portion of the eastern United States, resulting in coincident peak demand conditions in the northeast and southeast. During the early January event, northeast natural gas demands spiked to forty-two B.C.F. per day, the highest since 2009. Record cold blanketed the southeast, as well, and natural gas demand there reached an all-time high of twenty-five B.C.F. per day. High natural gas demand in the southeast coupled with coincident high demand in the mid-Atlantic and northeast, resulted in constrained conditions on numerous eastern gas pipelines, spanning from the Gulf Coast to the northeast.

Another major winter storm hit the northeast on January 22nd, sending temperatures, again, into the low single digits. Northeast natural
gas demand reached forty-one and a half B.C.F. per day, just shy of the record set during the early January cold spell, while southeast natural gas demand reached twenty-three point nine B.C.F. on the same day.

Natural gas pipelines serving the region issued capacity constraint warnings and operational flow orders, holding customers to scheduled flows. Additionally, many storage facilities issued restrictions on withdrawals. Local distribution companies also issued O.F.O.s, and requested that customers voluntarily curtail demand during peak load periods.

At least one point five B.C.F. per day of U.S. natural gas production was shut in due to well freeze-offs, with northeast gas production down, eight hundred M.M.S per day. More expansive transportation and storage constraints than experienced during the earlier January event, coupled with production losses and continued strong demand, resulted in severe operational strains, and manifested in unprecedented natural gas price spikes across the U.S.

The cold temperatures persisted
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into late January, when natural gas demand once again spiked reaching thirty-nine B.C.F. per day in the northeast, and twenty-three and a half B.C.F. per day in the southeast.

During each of these cold events, customers who had firm transportation capacity on natural gas pipelines generally managed to secure natural gas deliveries.

During the early January cold event, record natural gas demand pushed spot natural gas prices for delivery, on January 7, significantly higher. In New York, spot prices reached fifty-five dollars and forty-nine cents per M.M. B.T.U. at transcode zone six New York, while prices spiked to around seventy dollars per M.M. B.T.U. in the Philadelphia region and the mid-Atlantic with some intraday trades reaching upwards of one hundred dollars per M.M. B.T.U.

These high natural gas prices at major northeast points broke all previous records during the January 22nd event, propelled by more severe and widespread system constraints. Prices at transcode zone six New York, and transcode zone five reached one hundred and twenty dollars per M.M.
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B.T.U., while in transcode zone six non-New York, prices spiked one hundred and twenty-three dollars per M.M. B.T.U.

Those active in the natural gas spot market were at times exposed to these record high prices. Similarly, as discussed in detail later, customers purchasing in the R.T.O. energy markets were exposed to dramatic price spikes driven by high natural gas prices.

A week later, on January 27th, northeast prices, again, spiked almost one hundred dollars per M.M. B.T.U. However, this time the effects were more widespread, and the spot natural gas prices in the Midwest reached over fifty dollars.

Use of backup fuel oil by generators, liquefied natural gas from the Canaport L.N.G. terminal in Nova Scotia, and slightly higher temperatures than experienced in New York in the mid-Atlantic, helped ease conditions in New England.

During the early January event, prices in Boston reached thirty-four dollars per M.M. B.T.U. at the Algonquin, Citygates, while during the later January event, the price peaked at seventy-three dollars per M.M. B.T.U.
Most other U.S. gas trading hubs traded below six dollars per M.M. B.T.U. during those cold spells, with Henry Hub reaching seven dollars and ninety-two cents in February, the highest since hurricane Ike in September of 2008.

The electric markets in the east were stressed during each of the cold weather events. During the early January event, electric demand was at historic levels due to the extremely cold weather. New winter peaks were set in NYISO, P.J.M., MISO, and S.P.P. ISO New England reached a peak just short of its historic peak.

In the cold weather events later in January, regional demand in the eastern regions was high, but not at the level set in early January. However, the later periods did experience stresses, primarily because of historic natural gas prices, fuel delivery, and generator outages.

During the cold weather events, the historically high peak demand combined with high levels of generation outages placed the regions at near their capacity in meeting system demand. The R.T.O.s and I.S.O.s declared system emergency conditions on several occasions. And some
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implemented emergency procedures, including emergency
demand response, voltage reduction, emergency energy
purchases, and public appeals for conservation. They
issued several maximum generation warnings, and some
maximum generation actions during the period.

It is important to note that the
R.T.O.s and I.S.O.s cut no firm load during this
period. Where voltage reduction actions were taken,
service to customers was not noticeably affected.

Demand response resources were
activated to help manage the emergency. NYISO
requested voluntary reduction from about nine hundred
megawatts of its demand resources on January 7th.
Demand resources were notified of possible deployment
on January 28th, but were not activated. P.J.M.
activated about two thousand megawatts of demand
response for several hours during the morning and
evening peaks of January 7th, and it activated over
twenty-five hundred megawatts of demand resources
during the January 23rd and January 28th events.

Mechanical failures in generation
systems, fuel deliverability, and fuel handling
problems in the extreme low temperatures experienced
this winter led to high levels of forced generation
outages. These levels contributed to the stress conditions in the markets that led to emergency actions and higher prices. During the early January event, the R.T.O.s estimate generation of forced outages and derates ranged from about seven to thirty percent of load on a peak day. Significant portions of those outages were related to fuel issues, including gas curtailments, no fuel, oil delivery, and frozen coal.

New York I.S.O. experienced a high level of fuel and cold weather related outages on January 7th, which declined significantly during the later January and early February events. P.J.M. estimates that about one-quarter of the forced generation outages on January 7th were fuel related. In addition, five thousand megawatts of combustion turbines failed to start when called. During the later January events, gas curtailments declined in P.J.M., as did start failures for combustion turbines.

I.S.O. New England experienced a lower level of forced generated -- generation outages on January 7th relative to other R.T.O.s. However, all of the outages were attributed to intraday
natural gas procurement difficulties.

FERC staff continues to examine the causes of the forced outages, including ascertaining the extent to which the fuel issues were supply or delivery related.

Coal and natural gas generally maintained their shares as fuel for electricity generation during 2013. Preliminary data for January 2014 indicates that the sizable increase in electric demand was served from mostly coal-fired generation, while natural gas fired generation actually declined slightly between December '13 -- 2013 and January 2014.

Oil-fired generation increased from one point three to five point seven gigawatts hours in the same timeframe, although the January total only amounted to about two percent of the total generation nationwide. In New England and the mid-Atlantic however, the proportional shift was more dramatic. New England saw twelve percent of its electricity produced from oil fired generation in January, up from three percent in December. While in the mid-Atlantic, which includes New York, almost five percent of electricity was produced from oil
fired generation in January, up from about point three percent in December.

The oil fired generation replaced natural gas fired generation due to a combination of high natural gas prices and stable, but now relatively lower oil prices, particularly at the end of January. In other cases, oil fired generation was used because non-firm transportation service was unavailable to many generators. The output from other fuels not shown on this graph was relatively flat for the period.

During the early January event, the high loads based by the electric markets were the main factor that led to high prices, requiring the R.T.O.s and I.S.O.s to dispatch more expensive generation to serve the higher loads. The electricity prices also included the impact of high natural gas prices, and the impact of scarcity prices during the limited number of hours. During this event, the L.N.P.s were near or even above two thousand megawatt hours for a number of hours in P.J.M., and a few hours in NYISO. On peak, average real time prices ran from three hundred to seven hundred dollars per megawatt hour in these regions.
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The subsequent cold events in January, February, and March also resulted in similarly high prices that the key drivers changed. During those later events, the prime factors leading to natural high gas prices were historically high natural gas prices. Due to the elevated levels of demand, most of the regions were operating at the high cost levels of their supply status. And in many cases, this meant oil units that are not often used because they are not in economic merit order.

Additionally, some dual fuel generators were forced to use oil when non-firm generation of natural gas became -- transportation of natural gas became unavailable. And on some days, high natural gas prices made oil fired generation more economic to dispatch than natural gas fired generation. Head-to-head price competition between oil and gas for power production is something that has not occurred much in recent years.

As natural gas is the marginal fuel for most electric energy markets, the price of natural gas plays a leading role in setting the price of electricity. As natural gas prices soared and retreated through the period, electricity prices
followed, as illustrated by this graph, which shows P.J.M.'s experience. Unprecedented natural gas prices raised the possibility that some generators would need to offer below their variable fuel costs that they were required to stay below the one thousand dollar offered cap.

New York I.S.O., P.J.M., and California I.S.O. all sought and were granted waivers of the existing market rules in order to allow generators to offer power at higher prices or otherwise recover high fuel costs. In addition, the high locational marginal prices in the R.T.O.s and I.S.O.s did not reflect the entire costs of these events.

In these markets, there are provisions in place to reimburse generators for costs that are not covered through normal energy and ancillary service market sales. For example, R.T.O. and I.S.O. operators may commit additional generation out of merit order to ensure reliability. These costs are then generally recovered broadly from loads through so-called uplift. Uplift costs for the month of January with a total uplift incurred by the R.T.O.s for the entire year as operators took
conservative actions to maintain reliability during
the cold weather events.

FERC's Office of Enforcement,
Division of Analytics and Surveillance routinely
monitors wholesale natural gas and power markets at a
more granular level to look for potential market
manipulation, and any other inappropriate behavior by
market participants through the use of automated
screens that sift through a variety of public and
non-public data. The screens were built by division
staff, and based upon no manipulative schemes, market
rules, behavior that could constitute manipulation,
statistical measures that help identify market
anomalies, and persistence measures. Analysts
regularly review and analyze the output of these
screens to determine whether the behavior identified
by the screen requires additional analysis or follow
up.

This routine screening initially
revealed the unprecedented volatility of the natural
gas markets. At the time, staff wanted to determine
if these prices were the result of market scarcity,
and whether any market participants were engaged in
market manipulation. Some of the initial data points
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were screen alerts for natural gas market participants with high market concentration, seeming to purchase at ever escalating price levels, primarily in the east and the mid-continent.

Following their normal process, Division of Analytics and Surveillance staff followed up on these screen alerts. Staff interviewed natural gas suppliers, traders, and generators, coordinated with system operators and market monitors, and reviewed available data from R.T.O.s and I.S.O.s, and other sources.

In terms of preliminary observations, natural gas prices were high and deliverability into market areas was a concern. Although, shale supplies were plentiful, some gas did not make it to market demand centers in the east due to pipeline constraints, contributing to the extreme basis differentials in the price.

Some counterparties sold physical options, often to natural gas utilities, and then had to scramble to fulfill those obligations with the commodity when they were called or pay high financial penalties. Going into the winter many market participants expected plentiful supply and pipeline
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capacity, consistent with recent market conditions. When the prices for trading from January came in so high, almost twenty-two dollars from M.M. B.T.U. in New England, for example, some companies decided to go into the month in short position, thinking prices could only go down. When January prices began to spike, entities that took this approach stood to have large losses as they entered the spot market to obtain needed supplies.

Generators were hit particularly hard by market stresses and high spot natural gas prices. Market stress was exasperated by operational logistics, in particular, requirements that generators consume gas on a twenty-four-hour ratable basis due to pipeline operational restrictions. Some generators found it difficult to accommodate dispatch directions that required them to buy intra-day gas.

System operators managed the high demand periods and generator inflexibility with conservative operations that, as noted earlier, led to high amounts of uplift. Examples of this conservatism included earlier than normal commitment of generating units, to ensure gas availability, in not committing fuel oil units that were economic.
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Instead, conserving them for an anticipated peak, thereby, putting more pressure on the gas market. The Office of Enforcement has not seen indications of market manipulation thus far, but their review is ongoing.

FERC held a commissioner-led technical conference on winter 2013-2014 operations and market performance in the R.T.O.s and I.S.O.s on April 1st, 2014. In the morning, commissioners received a presentation from FERC staff, summarizing overall marketing system conditions during periods of extreme cold temperatures last winter.

Each FERC jurisdictional R.T.O., I.S.O. then provided presentations discussing, among other things, the impact of the cold weather events on operations and market conditions in their region, how they prepared for those events, and the steps, they took in real time to manage any operational impacts. In the afternoon, a panel of stakeholders, including electric utilities, electric generators, natural gas pipelines, natural gas L.D.C.s, and consumer representatives discussed the operational and market impacts of these events from their perspectives, and offered ideas regarding lessons
learned from these events that could be applied in
the future.

Finally, the FERC commissioners and
state commissioners from several regions, including
Chair Zibelman, concluded the day with a roundtable
discussion reviewing what they heard during the day
and lessons learned. Post-technical conference
comments are due today, May 15th, 2014.

Thank you very much.

CHAIR ZIBELMAN: Thank you.

Mr. Addepalli?

MR. ADDEPALLI: Good morning, Chair

Zibelman and Commissioners. In addition to me, I
have staff who helped put together this presentation,
Michael Twergo, our chief of electric rates and
tariffs, our supervisor in the bulk electric systems,
and Cindy McCarron, our deputy director of gas and
water.

Jeff just presented the regional
views. I'll focus more on New York specific, and try
to tee up some of the issues associated with both the
supply and price, and see what lessons learned, and
what we need to focus on for the next winter and
beyond.
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So looking at New York specific, as Jeff said, it was a cold winter, as all of us know how cold it was. One metric that is pretty typical that we look at to assess how cold it was is the heating degree-days. What we show you here on this chart is for the last decade or more, how many heating degree days were there in New York in both Albany location and in New York City.

If you look at the last bar, 2013-14 winter, that's the coldest or one of the coldest winters in the last twenty-eight years that we have seen.

On the next slide, as a result, and partly due to that and other reasons, as Jeff said, the prices have gone up significantly. The gas prices -- the natural gas prices, and this shows you for the last number of winters the natural gas prices at different hubs, the transcode zone six, Iroquois, and Algonquin, Citygates, and plotted against the heating degree days. The more heating degree days, the higher the prices are. And the prices, as you will see, this past winter were the highest in the last seven numbers that are shown there. So we have the highest gas prices in New York this past winter.
And given the coldness, you will also see this chart shows you, on the electric side, the demand on the system for the whole New York control area. On the top, you'll see the summer peaks, and typically which we are concerned about in the electric system. At the bottom, you see the winter peaks, and this winter is a record. So we set a record in New York this winter with twenty-five thousand seven hundred thirty-eight megawatts.

By the way, last summer was also the highest load that we had in the last number of years.

And so the coldness led to high electric demand, and that led to the peak demand that we had on the system. So as you said, and as Jeff said, this led to some supply issues. On the next slide, I'll just tee up and you'll hear a lot of this from other panelists, too, later on in the supply panel. The generator meter rates that Jeff mentioned affected even in New York and created a tightening supply situation. New York I.S.O.'s Wes Yeomans will go into more details.

Basically, what the reasons were for the derates, whether they were fuel related
derates, or whether they were weather related, or some other reason why the generation was not available on some of the critical days. As we also heard just now, the natural gas was not available for certain interruptible gas generators on critical days. So that led to the use of alternate fuels. And again, on certain critical days in January and February, even the dual fuel units, there were issues associated with procuring alternate fuels.

So these are some of the lessons that we have to look at from last winter. What did we learn and how do we fix any problems that we can for the coming winter and beyond in terms of available fuel, alternate fuel, especially so we can ensure reliability of the system?

Demand response is -- is a typical element that is invoked primarily during summer when we have high demands on the system. But for the first time this winter, also the New York I.S.O. invoked demand response. And Wes Yeomans tells me this is the first time we did this since 2001 in the winter period. Maybe to help other neighbors perhaps. And again, in terms of regional, we do export and import from our neighbors. And on some
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critical days, there were issues with imports from P.J.M. and the fact that we were exporting to P.J.M. So some of these are the supply issues that need to be addressed and discussed in the next panel and beyond, as to what lessons can we learn, and what do we need to do after that.

Looking at prices, as we focus on prices, this chart shows you since the I.S.O.'s conception in New York of the eleven regions, the three major points that are flagged here are in the western part of the state, and the Capital District, and in New York City. And as you'll see, this price in January 2014 is the highest in record over the last fourteen years. We hit over a hundred and sixty dollars per megawatt hour in New York City, and over a hundred dollars in the west. This is an unprecedented level of price in New York on the electric wholesale markets.

Now, just looking at the last year versus this winter, last winter versus this winter -- the previous slide was looking at the last fourteen years. This one is just focused on last winter through this winter. Again, West, Capital, and New York City, the prices escalated significantly, almost
two to three times, especially in January and February. And again, the high prices in West, and New York City, and Capital have affected consumers on their bills, as we'll see in a minute.

On the next slide, as Jeff said, there's a high correlation between natural gas prices and electric prices. This shows you last winter versus this winter in New York, for the Capital District and in New York City the gas prices for those pipelines, and the electric corresponding prices and there's clearly a high correlation between high gas prices and corresponding high electric prices.

This one is an interesting chart that shows you there was a price separation between the western part of the state and the capital. And this will become relevant as we look at utility hedging practices, as you'll hear in the price panel later on. The -- this chart shows you, for the last ten -- eight or nine years, the difference between the price -- west and the central region for those hours in those two months, January and February. About fourteen hundred hours in those two months.

So what this shows you is the
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bluest bar on the top is the last winter, January and February, price differential was the highest among all those years by almost a multiple. So there's a huge difference between the west and the capital this winter, especially, and the price panel will explore some of the reasons why.

On the next, this is a different way of looking at the same information. But just for this last winter versus this winter, those two months again in January and February. If you look at those fourteen hundred hours in those two months, and how many hours was the price spread over a hundred and fifty dollars between these two points, the west and capital. So in 2013, there were only nine hours out those fourteen hundred hours that the price differential was over a hundred and fifty. But in 2014, that price differential existed for a hundred and fourteen hours. Clearly, a huge multiple compared to the last winter, showing that there's a huge price spread -- a sustained price spread those two months between West and Capital.

And the next slide, please.

Another interesting observation on this slide that you'll notice is, as we said before, we do trade with
our neighbors, I.S.O. New England, and P.J.M., and H.Q. Ontario. Here this shows just the New England, as we import and export. The more we export to New England, the price spread increases significantly. So what you see in that red line is the price spread between Zone A West, and Zone F Capital, and the blue bars are the levels of export. So the more we export the more the price spread is pronounced.

And so what does this all mean to customers, these high levels of electric prices? So we show you Con Edison in the city, a typical customer with three hundred and fifty kilowatt hours' usage per month, and the Niagara Mohawk, National Grid customer in the West and Capital, a typical usage residential of six hundred kilowatt hours per month.

Clearly, the prices went up from November, December, to January and February, January especially. And so much that in the Capital District, National Grid predicted a huge impact, and asked the commission to suspend that increase for the month of February, and spread that increase over a number of months to ameliorate the bill impacts.

And on the next slide, as a result,
as -- as the chair said at the beginning, we have received a huge number of complaints at the commission. Just looking at the high bill complaints last year versus this year, it's almost three times as many complaints that we received as a result of high bills.

So on the price, some of the observations are these are some of the highest prices that we've seen, the electric prices this winter. Clearly driven by high natural gas transportation costs to generators. That's where it goes into their marginal price that sets the electric price. And so we look at what solutions would be needed to address this concern. As the chair said, this is not going to be a one-time event. This may be a recurring event in the future. So we need to find solutions to address this problem.

Second, we also see the spread between West and Capital, perhaps due to electric transmission congestion. While the first one is gas transportation issues and pipeline congestion, the second one is electric transmission congestion. And we need to address that, as well as to how do we reduce that congestion.
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And the third is an observation that the more we sell to our neighbors in New England, the higher Capital District prices. Clearly, New England is taking actions based on the lessons learned for them. And we should be monitoring and seeing what else we can do here in the Capital District to -- to address the concerns.

So that's a very high level teeing up the issues for you to consider as we go through the remaining -- remaining panels. And we're available if you have any questions, collectively.

CHAIR ZIBELMAN: Thank you for both the presentations. Obviously, highly informative and I appreciate the analysis, both done at the FERC level, and by staff in back casting in trying to look at trends and information so we can start grappling with what's happening.

Mr. Dennis, just a brief question for you. I think post the April 1 session, FERC has also initiated some dockets. And it may be that there are people in this room who are not aware that there are other proceedings that FERC has now started. I wondered if you wouldn't mind just summarizing some of the additional proceedings that
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FERC has begun to begin tackling these issues?

MR. DENNIS: Well, in terms of additional dockets --.

CHAIR ZIBELMAN: Or proceedings?

MR. DENNIS: Yes. We've had a few -- there's been a few filings. We've, of course, had some -- the filings I mentioned dealing with the price cap issue, and generator fuel recovery. We're receiving comments today on the April 1st technical conference. The -- the chairman kind of asked folks to -- to look at both what are the near term things we can be doing before next winter. What are the things we could and should be doing, versus what are the longer-term things we need to look at? So that -- that's kind of where we are now.

There aren't sort of April 1st or winter specific proceedings, other than those that I mentioned going on right now. Certainly, we've had some individual filings from P.J.M. and others to make reforms to their capacity markets heading into both next winter and looking further out. I.S.O. New England has made some filings with us, as well. And so those are the -- the kind of things we're looking at. Also, dealing with their capacity market.
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CHAIR ZIBELMAN: Okay.

MR. ADDEPALLI: I -- I believe -- believe the other proceedings deal with more on the natural gas side on trading between electric and gas day, making sure consistency between the two. And also posting on the bulletin board, buyers and sellers data on intraday trades. Those are the kinds of issues that the FERC also teed up for comments.

CHAIR ZIBELMAN: And I --.

MR. DENNIS: Yes. Sorry. I should've mentioned the gas and electric coordination. To me, that was the best thing going on for so long that I -- I didn't think of it as a last winter issue. But certainly, we initiated action on scheduling in March to try to better coordinate scheduling practices between natural gas, pipelines, and electric generators, as well. There is an industry proceeding ongoing now to try to grapple with the -- the Strawman proposal that the Commission put out there. And we'll be hearing more about that in the coming months, and likely you'll see more activity from us in the fall.

CHAIR ZIBELMAN: Okay. Thank you.

And one more question. One of the
things when I was looking at your price slides, in terms of the markets, you noted that P.J.M. West was one of the highest prices. And you know, typically, it's P.J.M. East; right?

Now, was East higher or West? And the only reason I'm asking is because I'm wondering, for our purposes, and maybe this is a question we can ask ISO and Staff, if we're going to see trending in pricing outside of P.J.M. or outside of New York, will we be more worried when P.J.M. West prices go because it imports in, or East because we tend not to see as many imports from East? As a -- but I'm -- I'm just curious in terms of the -- because I -- the reason why is because of a lot of the cold, obviously, is in P.J.M. West.

MR. DENNIS: The -- I don't have specific data on how the imports -- what the level of imports was between P.J.M. and MISO, but certainly they traded with each other. And in some of those events, the cold moved across the upper Midwest, dipped down into P.J.M., and then moved east. So as -- as the cold dipped into that western P.J.M. area where both P.J.M. and MISO were dealing with that simultaneously, there were constraints that
impacted prices in the west more than they did in the east. And you saw some flows begin to move the other way. Normally, flows are west to east at P.J.M. as you mentioned.

CHAIR ZIBELMAN: Right.

MR. DENNIS: But because of the nature of these kind of particular cold, we saw that shift a little bit.

CHAIR ZIBELMAN: And so -- and then I'll put this to Staff. I mean, and -- and then maybe West when you're -- just so I understand because typically when we import from P.J.M., which we'll do, it comes from more east. So if there's constraints in the west, it's going to affect our ability to import, which will then affect prices. That's why it becomes a matter of interest for us. Is that a logical question?

MR. ADDEPALLI: Then yes, typically, we import on a net basis. I believe around ten percent of our energy. How much from the east and west, the ISO will have a breakdown.

CHAIR ZIBELMAN: Okay. And then one question for -- for you, Raj, as I'm looking at it. I think what's -- what -- in terms of looking at
the prices and the separation, that clearly was a -- was an issue that's affecting the Capital Region a lot, that we -- it was unexpected. I know we'll be talking about this later today, but had -- were there transmission constraints affecting that, as well? In addition, you know, I mean if I'm -- I know we're looking at the generation, but do you see that as an electric transmission issue?

MR. ADDEPALLI: Yes. Between the two points, West and Capital District, as we noted, the number of hours of congestion continues to increase. And part of that could be transmission constraints, and Central East constraints especially. We are tackling some of it in other proceedings, but there are opportunities, potentially, to address this on a more comprehensive basis that we need to look at.

CHAIR ZIBELMAN: Thank you.

Further questions? Commissioner Brown?

COMMISSIONER BROWN: Thank you. And Jeff, thank you for coming. Good to see you again. I really appreciate the work that FERC has been doing in this area and taking a
look. I just want to highlight a couple of longer term trends, and I'm not even really looking for a big response right now, but put it on your radar screen. And it was -- both of these that we mentioned a lot along the way.

We set up an electricity system that almost all our natural gas generators are interruptible customers. It's worked out pretty well because in the winter we need the gas for the heat, and in the summer we needed the gas for the electricity, and it's complemented each other.

Obviously, this winter we saw, perhaps, our first example of what happens if suddenly the electricity demand hits at the same time that we need the natural gas for its more traditional uses. And you might be able to attribute this to, you know, abnormally cold weather. But the question is how many -- how long this is going to go on for, whether this is going to become a pattern? And I note the D.O.E. study that's being done in the eastern interconnect planning process that's taking a longer-term look at this relationship between natural gas facilities and electricity facilities. And I know FERC's been involved in -- in that process, as
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well. But I think it's something that we really need to -- it's well beyond just looking back at the last winter. It's looking at a much larger trend. Is this a sustainable system, whereby we try to keep all our electricity generation facilities on natural gas?

Related to that was somebody who wisely made a decision many, many, many years before I got here that dual fuel capability was a very important attribute, especially in New York City. And it paid off big time this winter. Other regions, perhaps, didn't have those same requirements, and we saw some of the results on that, which gets me to my second point.

You can comment on this if you want, or just shake your head, whichever you feel like doing, Jeff. It's fine. The issue that Raj raised with imports, exports, we're in the midst of a lot of different markets here in New York, you know P.J.M. to the south, New England to the east and north, Ontario to our west, and we help each other out a lot. The I.S.O., during system stresses, there is constant trading back and forth to try to help each of the I.S.O.s maintain system reliability.

Again, a longer-term trend that we
should keep our eye on is if we see a prevailing pattern that, under certain system stresses, there's leaning going on because one system perhaps has dual fuel capability, and another system does not have dual fuel capability. And so I would hope that FERC would -- and I know they are, would be looking at some of these trends beyond just the short term what happened this winter, but the longer term are we setting ourselves up for any future issues in this regard?

MR. DENNIS: Thank you, Commissioner Brown. You hit on your first longer term trend is something that was an early takeout away, I think, for us from the April 1st conference, which is really the importance of dual fuel, and the importance of -- of fuel diversity in -- in our markets. And that is something that the Commission is continuing to look at.

We also have an ongoing generic docket, looking at capacity market structures. And that is certainly an issue that's been teed up there as well, is how do we ensure that we still have that -- that diverse set of resources and diverse fuels for these kind of events.
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I'm -- in terms of the second issue with regards to imports, we look at -- we call them seams issues, and we look at them all the time. And I know that New York and New England and P.J.M. have done a lot of work around coordinated transactions, scheduling, and other things. I expect that work to continue, and the Commission is -- the Staff is -- is always monitoring these things, and happy to talk with you more.

COMMISSIONER BROWN: Thank you.

CHAIR ZIBELMAN: Commissioner Acampora?

COMMISSIONER ACAMPORA: No.

CHAIR ZIBELMAN: Commissioner Brown -- or Burman? Sorry.

COMMISSIONER BURMAN: No.

CHAIR ZIBELMAN: All right. Thank you.

And we'll go on to our next panel.

(Off-the-record discussion)

(The hearing resumed.)

CHAIR ZIBELMAN: Good morning. We have panelists today and representing, I believe, almost all aspects of our consumer groups in New
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York, Michael Mager from -- a partner of Couch White. He'll be representing Multiple Intervenors.

Catherine Luthin is here to represent the Consumer Power Advocates. Marcos Vigil, with the Utility Intervention Unit, with the Department of State, in New York, and Gerry Norlander, who is the executive director of the Public Utility Law Project.

So welcome to all of you. I appreciate, again, your attendance. This really, ultimately, as we said, ends up being all about the consumers and what is happening with them. And it'd be -- the purpose of our panel is really to directly understand that real consumer experience, and really start thinking about what we can do to effectuate that in a much better way.

So beginning, I guess, with Mr. Mager.

MR. MAGER: Thank you, Chair and Commissioners. Multiple Intervenors is an association of over fifty-five large industrial, commercial, and institutional energy consumers.

Next.

The topics I'm going to cover are the impact of what happened this winter on Multiple
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Intervenors members and selected recommendations for addressing high energy prices. Next.

The gas supply issues we've had about had tremendous impact on Multiple Intervenors members. Members with interruptible transportation experienced frequent, prolonged interruptions, which led to unusually high reliance on alternate fuels. In some instances, facilities were required to shut down operations. Even customers with firm transportation also experienced interruptions due to local issues. And of course, gas prices in the spot market were astronomical.

Those gas issues, as -- as we've heard, led to historically high electricity prices. For many Multiple Intervenors members, these costs basically obliterated annual energy budgets by the first quarter of the year. One member reported to us that the company -- the entire company lost money because of energy prices in the first quarter. And even largely hedged customers experienced abnormal cost increases. Next.

Some representative impacts included, as I mentioned, very high impacts on costs. Capital projects were postponed or cancelled. In
some cases, internal investments that were targeted
for New York were shifted to other regions.

So I just want to hit upon three
recommendations. Multiple Intervenors believes
there's a pressing need to, one, increase interstate
gas pipeline capacity in New York. Two, improve
customer participation in, and the effectiveness of
demand response programs. And three, significantly
reduce surcharges to large, high-load factor
customers. Next.

I won't belabor this. It appears
that gas is the most economic fuel for energy for the
foreseeable future in terms of new and recent gas --
gas-fired electric generation. Gas-fired generators
set the marginal price for energy most hours of the
year. The gas problems this winter, from what we
heard, were primarily related to shortages in
capacity, not supply. It's clear that the state, and
probably the entire northeast, lacks sufficient
interstate gas pipeline capacity.

One potential concern we have is to
the extent the Commission is exerting efforts to
expand gas in the state's distribution system, that
may exasperate problems unless the gas transmission
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system also is expanded contemporaneously. And
another concern that we have is absence of
affirmative action by the state. New gas capacity
may be built through New York, but for the benefit of
other states.

It seems -- next -- it seems clear
that increase -- that pipelines will not expand in
New York absent long-term contractual commitments.
That's the way it's typically done. And it's our
opinion that neither generators, nor marketers, nor
customers are generally in a position to make such
long-term commitments. And we also have a concern
that if generators are forced to procure a firm
transportation capacity, it would likely increase
electricity prices significantly, and result in the
inefficient use of the gas system.

We have some thoughts on increasing
gas pipeline capacity. These are for further
consideration only, and are not firm positions. One,
we could require gas utilities to contract for
capacity, and then release the excess. The state
also could be involved in this, either through
NYSERDA or the Green Bank. Efforts could be
undertaken to increase storage capacity in the state,
which would be a partial solution, and could ease some of the peak period difficulties. And also, the state could facilitate efforts by third parties, such as developers, to expedite construction of in-state gas pipeline capacity.

The second major recommendation we have is we believe there's a need to improve demand response in the state. The level of surplus electric capacity in the state has declined considerably in recent years. Between 2012 and 2013, more than thirty-seven hundred megawatts of generation located in New York exited the market, and the need for successful for demand response programs is growing. The NYISO relies on such programs, to a much larger extent for reliability purposes. Also, demand response programs provide end-use customers with the means to influence energy and capacity prices.

The next page is a slide we prepared that shows how, during the last three summers, as the price for capacity has increased significantly, the amount of customers participating in the demand response programs and special case resources has declined considerably, by as much as fifty percent in the rest of state region.
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The next slide shows that similar effects are taking place, both in New York City and Long Island, so at a time when capacity prices are rising and you would think participation and demand response would be increasing, it's actually declining. Next slide.

The reasons for the declining enrollment are numerous, and I don't have the time to get into it now. Promoting demand response programs at the retail level could offset some or all of the failings of the current wholesale level programs, and we need to increase customer participation. And Multiple Intervenors looks forward to working with the Commission, and addressing demand response issues as part of the REV proceeding.

Finally, I would be remiss if I did not mention the pressing need to reduce customer surcharges. The S.B.C., E.E.P.S., and R.P.S. surcharges have grown tremendously over time. For large, high-load factor customers, those surcharges now exceed the cost of -- of traditional delivery service. And by that, I mean the customer charge and the demand charge. The impacts are huge for large non-residential customers. Next slide.
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In order to protect the confidentiality of our members, we prepared a couple of hypothetical examples. These are typical Multiple Intervenors members. As you'll see, for a typical Niagara Mohawk customer with a twenty megawatt demand and eighty-five percent load factor, the annual cost of the S.B.C., E.E.P.S., and R.P.S. surcharges greatly exceed the cost of delivery service.

A similar example is set forth below for Central -- a Central Hudson customer with a forty megawatt demand and a ninety percent load factor. I easily could provide the Commission, if interested, with many additional examples of how these surcharges exceed the cost of traditional delivery service.

And we note, however, the Commission's newly instituted proceeding on a clean energy fund may lead to steps in the right direction. But we believe strongly that relief is needed now on a more urgent basis. And finally, our concerns regarding the surcharges include not only their exorbitant magnitude, but also that large non-residential customers appear to be subsidizing programs targeted at small non-residential customers.
that number -- a number of these programs target things, such as reducing demand and should not be recovered on a per K.W.H. basis.

And finally, that there is a Sizable surplus that exists. According to NYSEMA's recent budgets, their -- the surplus exceeds four hundred million dollars, and easily could allow for some meaningful rate relief in this area. Thank you.

CHAIR ZIBELMAN: Thank you.

Our next panelist is Catherine Luthin. Welcome.

MS. LUTHIN: Hi. I represent Consumer Power Advocates. And Consumer Power Advocates members include most of the major medical and educational institutions in New York City. Next slide.

Ninety-five percent of the C.P.A. members actually hedge their portfolio. And they did it as a fixed price, which is going to tell a different story than most people on this panel. And they did that because they took a look at the natural gas prices. You know, in '09, natural gas prices actually declined significantly, and they hedged deals anywhere from two to five years in the future.
And it's a simple thing, you just take a look at how NYMEX is traded every five-year period of time. And they saw that the -- the price of NYMEX' basis is actually relatively low at that period of time. It just made sense, at that point in time, to actually procure their supply at a fixed price for a rather lengthy period of time.

So -- but the small accounts typically remained with the utility, and they're actually really small. I mean, I took a look at the size yesterday, and I would say the size is about one percent of a megawatt. You know, they tended not to hedge them, but I think that's going to change in the future.

We took a look at -- we do a lot of back cast analysis. We saw, you know, when we would price these smaller accounts, and then take a look at what they would be if they remained with the utility, they tended to benefit from the utility class average. So they tended not to put those smaller accounts in a competitive supply deal.

Next slide is actually an example of a large hospital. I just wanted to show this to you. The load factor is seventy-two percent.
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Operations was twenty-four by seven. It took a look at the fixed price. It was a pretty decent price. It was for New York City. It was sixty-nine seventy, and then I compared it to the day ahead price. So we took a look at 2013, and the fixed price versus the day ahead index. They would've paid ten percent more. For this client, it would've been almost a million dollars more for 2013.

The winter of '14, we took a look at it. And actually, if they had not been hedged, they would've paid two point seven million more, or a hundred and thirty-three percent. So it's significant. However, same client, the same customer, three small accounts that were supplied by the utility that were not hedged, it is -- it's -- so I -- I looked at it two different ways. I looked at it month by month, and I also looked at it the winter -- you know, the three months in total only because the numbers are kind of whacky. And I think part of it, if someone from Con Ed is here, is because I think pricing on the utility lags. I believe that. I think the numbers are showing that to me.

But so I compared the day ahead
price to the utility full service price. And the utility price is actually fifty-two percent more. But then February and March, it was eighteen and sixteen percent less. The day ahead index price versus the utility price ended up being four percent more. However, if they had -- if I -- if they had been put into a fixed price deal, you know, the same portfolio that for the larger accounts, they would've saved a hundred and twenty-six percent, you know, less than what they actually ended up paying. So it's a problem.

And the next slide is actually, you know, why they did what they did. You see the gas prices trending down in '10. You know, that's when the majority of these deals were put in place. You know, and they just saw, you know, the market is just so low, let's just take it out. Next slide.

In general, because they're institutions they're really risk adverse. They were involved in the deregulation of the electric system. I was with Mike back then. And it was important to have consumer choice. But it was really important for them to be able to budget with some degree of certainty what their costs are, because there's so
many other aspects of their budgets that they can't control.

So they -- in general, you know, them being able to take a look at a budget with certainty is extremely important to them. So their -- their risk tolerance is actually really low, but they have done different procurement methods at different points in time. And market timing is everything. So I'm going to talk about that now.

Now, we're actually in a rising market. Most of them are actually looking at different strategies because it's a different market completely. So you go back to that slide that I showed a few pages back, the historic energy prices, you see the prices are beginning to trickle up -- back up. So the fixed price deal that they executed in the past isn't necessarily -- would be the wisest choice if you take a look at what the risk premium is.

So you take a look at different hedging strategies, whether you looked at a fixed price deal, or a blocker index, or you put a ceiling in, and you figure out what that premium is, using a back cast analysis. It's all you can do. So when
they executed those deals, the risk premium for a fixed price deal, at that point in time, versus the other supply strategies was really low. It was two percent, three percent, the cost of living. So they were very comfortable executing those long-term supply deals.

That risk premium for a fixed priced deal now is different. It's much higher. It's anywhere between five and eight percent. And I think as the volatility in the market increases, it will be higher. So they'll think about doing that. They'll do some sort of seasonal shaping. They can do that with their supply.

You know -- you know, one of the questions that you guys asked was credit, and I wanted to address that. You know, if you have good credit, you get better pricing. If you have worse credit, that risk premium that we talked about is actually going to increase in the price that's offered to a customer. It's as simple as that. The market prices it that way.

However, you know, consumers can negotiate. You know, if they make it part of the negotiation process, budget pricing, that's an
option. And we do have C.P.A. members that are in budget pricing deals.

My recommendations for consumers are you really need to spend some time to review and negotiate your supplier contracts. One thing that Raj had mentioned was how much more the -- the consumption with the -- with the -- had increased. So you could actually negotiate a bandwidth that can be fairly substantial. And but -- you're not going to get it if you don't ask for it. So that's something that I'm saying you could do.

You -- and you also need to pay attention to your weather normalization. You just don't go back one year and say this is the number. You need to look at it several years, and really, weather normalize the consumption pattern. And that puts you in a better supply deal right there. You -- you know, considering how extreme the weather was, exploring weather hedging is something that some of our clients are looking at. So that's something to do. You should monitor the markets, establish an active market management strategy, especially in a market in which you see the prices rising, which is where we're heading right now.
Our clients for dual fuel, they did suffer prolonged interruptions. I would say that there were some operational issues because the interruptions were so prolonged. I know that we just got out of a rate case, but we had never experienced that long of an interruption. And I think one of the things that the Commission needs to take a look at is, with such a prolonged interruption on these dual fuel customers, how do you address the operational concern, the maintenance that arise when they're on an interruption for that long a period of time.

CHAIR ZIBELMAN: I just wanted to write a note. Thank you. It was very informative.

Our next panelist is Gerald Norlander, and welcome. And Gerry, you represent the Public Utility Law Project.

MR. NORLANDER: Yes.

CHAIR ZIBELMAN: So thank you for joining us today.

MR. NORLANDER: Thank you. Good morning, Commissioners.

Next, please.

Before the winter of price spikes, customers were behind in paying their bills.
Customers owed about six hundred fifty-two million dollars in December. That represented about six percent of the trailing twelve months sales. Next. Twelve percent of the customers, before the spike, were sixty days or more late in paying their bills, many of them incurring late payment charges of eighteen percent. And I would point out that public assistance recipients may not be included in this because many of them have their bills paid directly by the welfare departments. And then the welfare departments reconcile at later times, and reduce the future welfare grants to adjust for the higher prices. So these figures are -- are largely hitting people who are not on welfare, who are -- who lack savings, and are in debt to the utility. When households experience a price spike, they are thrown into chaos because many people don't have the savings to absorb the price shock. Some research suggests that maybe twenty-five percent of households are -- don't have significant savings. And so therefore, a price jump of a significant amount will come right out of that month's expenditures for other items -- other discretionary
items in the consumer economy for other household needs.

And the -- the way people address it is by borrowing more, or incurring late charges, or sacrifice in other necessary household items.

Next.

About -- before the spikes, about five hundred and ninety thousand final termination notices per month were being issued by the investor owned utilities. That does not include LIPA, P.S.E.G. And we -- the trend before the spikes was rising sharply, and we suspect that when the data comes in it will show an even greater spike. And we think that perhaps, people will owe a billion dollars or more to the utilities when we see the data for January, February, and March. That data, we've asked for it, but it's not yet come in. We should get it in June, we're told.

There were twenty thousand -- twenty-one thousand monthly shut-offs, again, excluding the LIPA, before the spikes. And this is the key month. April, May, June are very high months for terminations because some companies forebear.

The data here is a trailing twelve-month average. So
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it -- it -- it's dampened, and we'll see a large
spike in shut-offs this month.

On the pricing trends, we -- we
know that the -- the FERC has allowed market-based
rates. We allowed the utilities to divest their
power plants, and they're now owned by merchant power
suppliers, who predominantly in the I.S.O. markets or
influenced by I.S.O. market prices. So even if
contracts are made, they may be indexed either to gas
or to I.S.O. prices.

So the -- the role with long-term
contracts has diminished since the -- the
restructuring. The natural gas fuel is only
thirty-seven percent of the New York's power
generation. When the natural gas price spikes,
the -- the price of uranium, or water, or wind does
not go up.

We have built a pricing structure
with the gas plants setting the clearing price. And
beneath that is -- is the spot market for gas that is
setting the price for the peakers. So if -- you
know, some people believe the world exists on the
back of a turtle. This is -- makes as not as much
sense, in my view.
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CHAIR ZIBELMAN: You may win the award for the most innovative slide.

MR. NORLANDER: We see the I.S.O. puts out a chart that -- it usually shows that electricity prices track gas. Next.

What we see here is it goes back a little further before the I.S.O. We see, on the left, what the typical bills for residential customers in the years before the I.S.O., and then we see the -- the effects of the restructuring. These are typical bills, snapshots for January and June -- or July of each year, and they don't capture volatility in other months, which didn't used to happen before the -- this because we used to have summer and winter rates. And that's what the little ups and downs were on the left before 2000.

We see the red line on the right. On the right axis, that is the arrears of residential customers. And we just -- the data that we had was limited. We couldn't go back further. But I think we see rising arrears with the rising prices and rising volatility.

The state law favors stable pricing. It has been a longstanding rule that we
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don't allow major price increases without an ordeal of eleven month. We have the seasonal rate variation was limited to -- to usage beyond the first two hundred fifty kilowatt hours. We don't allow mandatory residential time of use rates. And the -- originally the -- the fuel adjustment clause was used to true up changes in diverse fuel costs blended power generation costs, and now that has been used to flow through true-ups of the prior months I.S.O. prices, basically, as modified by -- by some contracting.

Our recommendations, we need low-income rate improvement, we need a universal service fund to support it. That should be at the I.S.O. level. We need to do -- create some performance incentives for continuous rates. We should look at long-term contracts requiring the utilities to provide a fixed price option. And that we should look at some of the generators that are setting that clearing price to see if they're financially creditworthy, and whether perhaps the Power Authority could take some steps, as they did in 2000, if there are problems with the viability reliability of the peakers that are too dependent on
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next day prices. Thank you.

CHAIR ZIBELMAN: Thank you very much.

And our fourth panelist, is Marcos Vigil. Marcos, welcome.

MR. VIGIL: Thank you. Good morning, Chairperson Zibelman and members of the Commission. Here, in my capacity as deputy secretary of state, overseeing the portfolio for the Division of Consumer Protection, and also participating as interim director for the Utility Intervention Unit, or U.I.U., on behalf of Secretary Perales, I thank you for the opportunity to speak to you.

First, I want to say that the U.I.U. supports the Commission's request for FERC to review the natural gas markets during the winter weather events. New York consumers experienced extraordinary charges for gas and electric services this winter, as we all know.

And also, the Commission recommended that utilities ensure that customers at risk of disconnection were aware of the availability of the deferred payment plans and budget billing. So utilities responded a number of different ways to
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this recommendation, including issuing press releases, running advertisements, disseminating email blasts, posting messages on social media, and inserting messages in bills to consumers to explain the options available to pay and provide for general information about the energy supply situation.

However, our experience dictates that these warnings were insufficient to forestall the effects on consumers. In January, for example, Con Edison suggested that its typical consumers would experience a gas bill of approximately sixteen point five percent higher than the prior year, and an electric bill about twenty-one point six percent higher, and they encouraged the customers to make use of the leveled payment plans.

Also, in January, National Grid requested and received approval from the Commission to defer an upcoming increase in the electric supply prices for Upstate New York residential and small business customers. National Grid also requested and received approval to provide incremental assistance to its small vulnerable customers.

What the company proposed was two emergency programs that would enhance both its arrear
forgiveness programs and its electric low income discount program. These emergency programs provide for an additional one-time bill credit for customers. In addition, they requested further relief for the vulnerable population, stating that it would make a shareholder contribution of one million dollars to reopen its Care and Share program, providing bill credits up to two hundred and fifty dollars for HEAP eligible customers in arrears.

In February, Central Hudson advised that its customers would experience a gas bill twenty-five percent higher than last year, and an electric bill thirty-eight percent higher than last year. They also encouraged them to enroll in a budget-billing plan, and to enter into a deferred payment agreement, and payment extension plan.

From January 1st to April 30th of this year, the consumer assistance unit, which is another unit within the Division of Consumer Protection, received about thirty-five complaints from consumers specifically about higher electricity bills. Despite notifications from the utilities, D.C.P. fielded complaints from consumers who were unaware of the rising energy supply services and
believed that their respective utility company had unjustifiably raised the price for their services. About twenty-five percent of these customers complained that they were on a fixed income, and had difficulty paying these higher bills. Many refused to believe their utility's explanation that market prices had increased during this period, and demanded that their company be investigated. About ten percent of these callers wanted also to know why the government was not doing enough to regulate the utilities.

I personally spoke with one of these consumers from Evans Mills in Jefferson County. She complained to me about her cost for electricity, excluding delivery service, more than doubled since December. In her complaint, she wrote that her cost from December to January jumped to about two hundred and thirty-eight dollars, and then her January-February bill again jumped to three hundred and thirty-two dollars for her February-March bill.

I was able to provide to this consumer some information regarding the spike in prices, and it was readily apparent to me that, explanations aside, the price spikes had a very real
and detrimental impact on these types of residents around the state, many of whom lived on a fixed income, and had no means to cope with the higher price. The Commission, obviously, as was shared earlier by Staff, dealt with much higher volume of complaints, three times higher than last year. But I am sure that the customer service representative who handled most of these calls heard the same lack of understanding about the wholesale energy supply markets evidence in the ones that we received.

As stated earlier, the utilities did reach out to their low-income customers and explained options available to them, such as, low bill and -- low-income bill discounts, HEAP, emergency HEAP benefits, and NYSERDA's Empower program, which makes energy audits and energy efficiency measures available to low income customers.

In the future, however, we believe that utilities should also reach out to the community action agencies within their territories to provide further assistance to customers who are having problems with their utility bills. This is something that we do at the Division of Consumer Protection,
given our interaction at the Department of State with many of these agencies around the state.

Better collaboration with these entities would further the goal of ensuring that customers receive adequate information from sources in their own communities that can assist them to better take advantage of all the benefits that are available to them in New York State.

Our website at the Department of State contains information, and a complete list of these community action agencies, and other neighborhood based organizations working for low-income customers. As part of our role, the U.I.U. would strongly encourage the state utilities to partner with these organizations, and we will be setting up those meetings between the utilities and the community action agencies in their territories to foster their relationship.

I would be remiss if I also don't mention the existence of what Governor Cuomo created, which is the Office for New Americans. There are twenty-seven regional offices across the state, which are -- can also help. Many of them have partnered with community action agencies, and they are in the
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service territories available to reach out to those vulnerable customers, many of whom may not necessarily speak English as their native language.

In order to lower the impact of future drastic wholesale prices increase electricity bills for residential customers and small businesses, the U.I.U. also recommends that the Commission look into its most recent national fuel gas order conducted on May 8th. The order requires N.F.G. to establish and fund a seven point five million deferred credit account for the benefit of ratepayers. As stated in the order, this account would be allocated equitably among service classes on the basis of delivery revenues, net of commodity, and would be used to provide refunds directly to customers to fund certain programs for low-income ratepayers.

The U.I.U. recommends that the Commission apply these same principles in -- that they used in the N.F.G. order to other potential utility over-earnings. If there are future drastic price increases, similar to the ones under consideration, the Commission should direct the excess earnings not to be deferred for future use,
but instead, to be applied to current customer bills.

Finally, I have to address another role that the U.I.U. can play in order to help ratepayers. Upon Governor Cuomo's request, the U.I.U. intends to ramp up its advocacy on behalf of consumers of the wholesale electric market. As a result of a settlement agreement between the FERC and Constellation, the U.I.U. has been awarded funding for this specific purpose of strengthening its wholesale electric markets consumer advocacy. The U.I.U. serves as a designated consumer advocate when participating in matters before the I.S.O., and in particular, as a member of the N.U.'s consumer sector.

This week the U.I.U. issued -- just yesterday actually, a request for proposals to secure consulting and advocacy services to better represent the interest of end-use consumers through active participation in the governor's process of the NYISO. The services would include seeking changes to the design of the NYISO's market rules that would benefit end-use consumers, and advocating against proposed changes that would harm end-use electric consumers. A secondary purpose is to secure
consulting and advocacy services to assist the U.I.U.
in its participation in selected deliberations before
the FERC.

I thank you for the opportunity to
address you on this very important topic, and in
advocating on behalf of the U.I.U. for residential
customers and small businesses around the state.

CHAIR ZIBELMAN: Thank you.

I have a -- a couple of questions.

In terms of hedging and this -- the idea of fixed
pricing, Catherine, you mentioned that your customers
typically like to go out for -- will go out for a
three- to five-year period?

MS. LUTHIN: It just made sense
during that period of time.

CHAIR ZIBELMAN: Okay. Do you
envision that if -- I mean, one question I had is are
there products that are available for longer term,
you know, sort of traditional five to ten, or ten to
fifteen?

MS. LUTHIN: Not that I'm aware of.

It's -- it's -- it was really hard to actually
execute that five-year term. But we did achieve
that. But five to ten year, no. And it made sense
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during that period of time, the market timing for
that long of a hedge in terms of the experience of
the market from the previous five years made it -- it
made sense.

CHAIR ZIBELMAN: And Michael?

MR. MAGER: Yes. I would -- would
give a similar answer. I -- I don't -- most of our
members, to the extent they hedge, it's more shorter
term, in the one to three years range. There's --
there's very few options for longer-term hedges.

And also, I think part of it is the
risk adverse nature of longer-term hedges for large
companies, the people who are responsible for energy,
the biggest or one of the biggest costs for a lot of
the Multiple Intervenors members. And if you enter
into an unfavorable long-term hedge, it's a good way
to be unemployed, frankly.

So it's -- there's -- there's a
risk adverse nature on the customer side in terms of
hedging on -- so no. There's nothing. Very few
members have anything of a longer-term nature.

CHAIR ZIBELMAN: It's a bit of a
chicken and egg. There may not be a product because
there may not be a demand?
MR. MAGER: Yes. I mean, I -- I sense one of the issues is there's not -- there's not a lot of bilateral contracts, certainly at the wholesale level in terms of voluntary. And there's not -- I mean, customers constantly look for hedges, but more of a short-term nature. And usually, it's not taking out a hundred percent of the load. They'll take out pieces of the load over time. You know, twenty-five percent hedge or something like that.

MS. LUTHIN: Yes. I mean, Audrey, years four and five had more of a risk associated with it. You can't account for the -- you know, where the capacity market is going to be that long a period of time, or what regulatory change may occur. So there would be more of a risk premium built into a longer-term hedge, too.

CHAIR ZIBELMAN: Okay. And let me ask you another question, and I think -- Mike, I think you brought it up, and I'm pleased -- you know, appreciate you doing this. I think that, you know, we're hearing -- we certainly heard in the first panel, and I think we'll hear throughout the day that there's a -- a scarcity now. It's not of supply, but
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actually of pipeline capacity.

And one of the things that you've brought up, and I would ask the other panelists to -- to talk about as a specific issue is that in our restructured environment, where is that demand for fixed transportation capacity most effective and most efficiently lies, because in the odd situation we're in, right, in that the demand for the fixed capacity may be coming out of the power customers. And the question is, is it -- you know, who would then purchase that fixed demand -- the fixed supply on the delivery sector to drive that so that it helps reduce volatility in the prices?

And your thoughts, and I would be interested to know you observed that you did not think it would be efficient to put it on the generators. Could you elaborate on that?

MR. MAGER: Certainly. We have a couple of concerns about the idea of forcing generators to buy firm capacity. First and foremost, that -- certainly the costs are going to be passed through, and because gas fired generators set the marginal price maybe eighty percent of the hours these days, those costs will not only flow through in
prices and go back to gas-fired generators, but all non-gas-fired generators will also receive those higher costs in the form of higher prices.

And also, I'm not sure that's the most efficient use of those resources for gas-fired generators who may only need it for certain amounts of time during the course of the year to lock into long-term arrangements for firm transportation on a twelve-month basis.

I -- you know, I -- I do think perhaps that to the extent that what we saw this past winter is a sign of things to come, there may be some generators that elect to, on their own, acquire some amount of capacity for economic reasons if they think they'll reduce their costs, and still enable them to, you know, reap the higher prices caused, you know, when other generators don't have that and are forced to go to the spot market. But I wouldn't impose that obligation on them.

CHAIR ZIBELMAN: And then my other question is down to -- with respect to the residential markets. Are you seeing any increased opportunities absent from the utilities from the retailers around offering fixed products coming out
of this winter? Do you see any -- anyone? Are you
hearing from your customers or clients? It could be
either Gerry or for Marcos.

MR. NORLANDER: No. We have no
data on -- on the percentage of customers who were on
fixed prices versus variable prices. And I think the
experience of customers, as far as we know it, is
that over time people pay quite a bit more for
service from third party -- party sellers.

MR. VIGIL: And with respect to the
U.I.U., usually our interaction would come in
every -- every so often receiving a complaint
actually on, you know, practices within the retail
market. And it's -- it's recently with respect to
this particular situation, we -- we didn't get any
communication as to what was the particular situation
of those low-income customers.

CHAIR ZIBELMAN: Okay. Thank you.

And then just one -- Michael, thank
you for -- for mentioning the REV docket. I think, I
agree with you that while we're talking about supply
in this instance, there's a lot we can do on the
demand side, and both at the commercial and
residential level. A big piece of what, obviously,
the Commission wants to do moving forward is make sure that we're managing the demand so that consumers who can respond are advantaged in terms of being able to both reduce their prices, but potentially, I hope, get into structured products that give them some price certainty and allow for that.

So more to come on that. And I -- and I agree with you. There's a lot of work that we can do to improve it.

On terms of, I think, the comments around disconnection. Gerry, your concerns and it's certainly a concern of all of ours is that when you have to go on low incomes and fixed incomes having these types of price changes are particularly hurtful. Although, I would say on the commercial sector, it's also hard because energy plays a very big, important part of costs. But I certainly appreciate the work that the U.I.U. is -- is doing, and I would encourage continuing to look at ways that working both of our staff, as well as with the utilities to see what -- what vehicles we can put in place moving forward to both provide the information, and then potentially greater -- greater certainty or greater avoidance of harm.
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So I appreciate that activity, and look forward to continuing to work with the new ramped up U.I.U., as we move forward.

Any further comments or questions from Commissioner Brown?

COMMISSIONER BROWN: I thought the panel highlighted exactly what the problem is that the customers that can least afford to see price volatility have the fewest tools to deal with price volatility.

What I heard Michael say is your customers get hit hard, but they do have some tools available to them in order to try to protect themselves, whether they work or not depends on what happens through the year. But I thought I heard Catherine say it's her larger customers, their creditworthy customers have some opportunities to do some creative things. But it's some of your smaller customers with poorer credit may not have the tools provided to them.

MS. LUTHIN: Well, no. No. Garry, they have the tools. It just costs more.

COMMISSIONER BROWN: Okay. So they -- they have the availability of the product.
By the next step was, I don't believe that a lot of the customers that Gerry's talking about even have the option of that product being provided to them. It's the question I want to ask the ESCOs, later in the day, whether there's even an opportunity for them to provide a hedged price over any long period at all.

You know, there may be an introductory fixed price. But that often morphs into a volatile price somewhere after a couple of months. So those are my impressions from what I hear. If anybody would like to correct me, and Catherine, you -- you did already. Thank you. I'd be interested in your comments.

MR. NORLANDER: I -- I do believe that the -- some of the utilities correctly perceived the problem that customers would have with volatility and offered a fixed price --.

COMMISSIONER BROWN: In budget.

MR. NORLANDER: No, not -- a fixed price electric and gas service -- fixed rate.

COMMISSIONER BROWN: Fixed rate.

MR. NORLANDER: And -- and the -- then basically at the Commission's urging they
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introduced variable pricing, and then at the Commission's urging eliminated the fixed pricing. I think that if the -- the entities that are capable of dealing in the wholesale market are the utilities that providing the service. The -- the ESCOs tend not to have the -- the credit, nor the certainty that they'll have customers.

And it may be possible still to structure some fixed price options from the utilities, and you have to deal with people hopping on and off, and that's done in other places. And that would provide some relief to customers who aren't interested in shopping, or don't want to expose themselves to volatile and uncertain pricing.

And -- and the chart that I had with the -- the different utilities and what their typical bills are clearly indicate that the utilities that were slowest to accept the Commission's urging to sell their power plants, and that entered into long-term wholesale contracts protected their customers better. And that would -- that would tend to be R.G. and E. and NYSEG, and Central Hudson.

And I think that if we look at the -- the information, we see that there -- there
have been ways, even after they sold most or all of
their power plants, for them to -- to provide
better -- more -- more stable prices to customers.

MR. VIGIL: And I would add to
that, that with respect to our recent experience in
rate cases, at least we are seeing some cooperation
with respect to the utilities in the N.F.G. order.
Niagara Mohawk, the recent case, as well as in Con
Edison, of providing alternatives for customers who
lack the sophistication to understand what their
options are.

And we have proposed, and the
Commission has approved, several opportunities for
bill calculators to be included, for information to
be available on websites, and we would encourage,
obviously, the ESCOs to explore options where some
fixed rate options are available for low-income,
particularly consumers and the really small
residential, and -- I mean, small business consumers
understand what their options may be.

CHAIR ZIBELMAN: Thank you. Thank
you. That's very helpful. We will move on to our
next panel, then. Thank you.

COMMISSIONER BROWN: Why don't we
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take five minutes?

2 CHAIR ZIBELMAN: Yeah, we are.

3 We're going to take a five-minute break.

4 (Off the record)

5 (The hearing resumed.)

6 CHAIR ZIBELMAN: We're going to

7 move on to Panel Two, which is actually Panel Three.

8 This is -- Raj always likes to trip me up, but it is

9 our second panel.

10 And this -- this panel's really

11 going to be focusing on issues regarding the

12 reliability of supply, as well as fuel adequacy. And

13 with us, we have Wes Yeomans, who is the Vice

14 President of Operations as a New York Independent

15 System Operator. Charles Wesley, who is the Program

16 Manager at the New York -- NYSERDA -- make it easier

17 on ourselves. Steven Parisi, who's the General

18 Manager of Operations on Con Ed.

19 And your -- your role is on the --

20 the -- the distribution --

21 MR. PARISI: Bulk power system.

22 CHAIR ZIBELMAN: -- bulk power

23 system.

24 MR. PARISI: Bulk power system, as
CHAIR ZIBELMAN: And Cortney Madea, who's Senior Counsel at N.R.G. Roger -- Richard Truxell, who's the Manager of Pipeline Control at Transco. Michelle Bloodworth, who's the Senior Director of Power Generation at the American National Gas Alliance. And Kevin Rooney, who's the Chief Executive Officer of the Oil Heat Institute of Long Island.

So, welcome all of you.

Again, for those of you who are just joining us, all the presentations are online and the marvelous bios of these folks are -- are -- are also posted, so we won't go through all of that. But -- well, we'll start then with Wes. Thank you. And thank you all for joining us today.

MR. YEOMANS: Okay. Thank you. The New York I.S.O. certainly appreciates the opportunity to be part of these very important discussions, especially in the areas of, you know, bulk power reliability and reliability to customers, market outcomes, and efficiency and planning processes. So, we -- we really are happy to be part of these discussions and hope to be helpful with
these initiatives going forward.

This presentation, we'll talk a little more about pricing outcomes. I know the audience has seen some slides on pricing outcomes, but we'll go into that a little bit in my -- my presentation. Also talk about the operating performance of the power system this past winter, especially during these cold time periods. And then I'll talk about next steps, at least with the New York I.S.O. in the areas of improved coordination, markets, and planning.

Everyone's aware of how cold it was this winter. We -- we think -- we measured as five major cold snaps across the winter. It seemed like it was just cold from December 14th to the middle of February, three different polar vortex' that extended across much of the country.

On January 7th, as -- as Raj mentioned, the New York I.S.O. did set a new record peak winter load of twenty-five thousand seven hundred and thirty-eight megawatts. Later that month, we had a forecast to even beat that and hit twenty-six thousand about the last week of January, but that did not happen. We were close to that. The
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prior record was set ten years ago at twenty-five thousand five hundred and forty-one. Quite frankly, I didn't think we would ever beat that again and we went flying past our design peak forecast of twenty-four thousand seven hundred and nine megawatts.

While the region, the -- while the regional -- and you think about these cold snaps, they extended across the country. These were very wide, geographically, in nature. We've had cold snaps before and we've had cold weather in the Northeast, but as everyone knows, these really extended across the south and much of the Midwest and the country. And the sustained nature, these were not one and two and three day in length cold snaps. Really, at the end of January, it seemed like it was about two weeks or eleven days.

But -- but the regional and sustained nature created tremendous demands on the gas and electric infrastructure systems. Reliability was met for millions and, quite frankly, several millions of -- of retail gas and retail electric customers consistent with Commissioner Zibelman's opening remarks.
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In New York, we still -- generation fuel diversity, dual fuel capability, and efficient market signals, all contributed to maintaining uninterrupted gas and electric supply to New York customers, in -- both electric and gas customers and millions of them, and reducing even higher consumer bills, really as a result of the diversity, the dual fuel and the market signals.

Next slide. Raj went through this.

I'll make two points. Again, we -- we hit a new winter peak after ten years. And when you think about the -- the initiatives in the efficiency area, and the initiatives with real-time pricing, you -- you know, you can get to a place where you think you may not ever hit another peak. But even with those very good and strong initiatives, we -- we did hit a new winter peak and just on the heels of six months ago, hitting a new all-time summer peak. And so -- so this is showing that.

And the other point I want to make is New York, for anyone that doesn't know, is still greatly, by about eight thousand megawatts, a summer-peaking entity, not a winter-peaking entity.

I'm -- I'm actually -- this slide
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is a -- a set of oil and gas prices and I'll go through this slowly, in a minute. This was for December. And I'll just make the quick point for December, that we had eight days where gas prices exceeded oil prices, at least on -- on the Tennessee Pipe and it was pretty close on the rest of the pipes.

But if we turn the page, we'll go to the very significant January. This is a busy slide, so let -- let me do this slowly. The black horizontal line, at about seventeen dollars, is the M.M. B.T.U. cost of oil, when oil's at about a hundred dollars a barrel. The many colored lines are the different gas prices at different gas trading points in the northeast. We won't go through the all the colors, but the significant ones are certainly the -- the -- the green, which is Tennessee, which crosses Upstate New York and goes into New England. And then the -- the Transco Zone Six, which is New York City.

If you add up the times where the colored lines go above the -- the black horizontal line of oil pricing, you get about twenty-two days. So, the point is there were about twenty-two days out
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of thirty-one, where the gas prices were higher than
the oil prices. And so -- so we can turn the slide.
And then if you look at the electric marginal prices
and we pick three points, we picked Western New York
as Zone A, Albany, New York as Zone F, and then New
York City as Zone J, the black line is the Zone A,
Buffalo prices, in Western New York. And the X axis
is two months. It's the month of December and then
the month of January.

And you can see that -- that -- I'm
sorry. The -- the solid blue line is Zone F, which
is Albany, and then the wider blue line is New York
City.

So, essentially, to the extent that
the two blue lines are top of each other, that
essentially means that the price was about the same
in Albany, as it was New York City. And that -- that
kind of indicates there were not transmission
constraints between the Albany or Eastern New York,
to New York City, whereas where you see gaps between
the black line and the blue lines, that's where there
is an electric price separation between Western New
York and Eastern New York.

So, you -- you see the first part
of the separation on the left side of the curve is middle December when prices first went high and gas prices went beyond oil prices. And -- and the -- the question was asked earlier and that's -- this -- this is related to the Central East Transmission constraint for about five, or six, or seven days. And then it would -- it became mild again, prices went low everywhere for a while, and then it got cold in January.

And you see the separation come back, really between Western New York and Eastern New York, bound up for two things. It was -- the pipeline system was constrained so the marginal price of gas in Eastern New York was significantly higher than the marginal price of gas in Western New York. And on the electric side, the marginal cost of electricity was higher because of the electric transmission constraints in the Central East, in Eastern New York, versus Western New York.

So, that then -- just, quite frankly, it's as simple as where -- where it became mild for some time periods, they kind of come back to converging, and then when it -- it got cold again, then -- then you see -- first of all, in late
January, you see it -- it's very cold and now gas prices were even higher in late January, than they were early January, so marginal prices everywhere, including Buffalo, went up. And then you see the separation, where there's a -- either a pipeline basis or an electric basis.

This slide, just kind of grounds the oil and gas price, as -- as -- as grounded for the last fourteen years. Or said differently, this is the last fourteen years of oil prices, which are the darker blue -- dark -- darker -- darker blue curve and then gas prices, it would be the green curve.

And a couple points I'll make here is that we still -- that -- this is not new, that we see a gas price in January. You can go back the last thirteen years and everywhere you see January on the X axis, whether it's January '03, January '04, January '05, January '06, this is not uncommon that we have a gas price in January.

Now, a couple differences or a couple things I'll point out, prior to the -- the large Marcellus Shale gas deliveries in about '07 and '08, you would see, before that time period, gas
prices exceed oil prices in January, maybe not the --
the other eleven months of the year. So that's not
completely uncommon.

Since the discovery of the
Marcellus Shale gas, while we still the -- the -- the
gas prices in January, post '06 and '07, you see the
spikes on the right on the lower curve, it still
didn't get as high as oil.

This winter now, was unique and
different, in that this January was the first time in
seven years -- not the first time we had a gas spike,
but two things. The first time we had a gas spike
where the gas went back way past oil and then you can
see by the chart, it wasn't a small spike, it was a
gigantic spike.

So -- so, when I say we've had gas
spikes before, while they look big at eight to ten to
twelve dollars, to put it in perspective, this past
January we had a spike such that when you average gas
for thirty-one days and you come up with a
twenty-eight-dollar average, that's a very, very high
spike to see on the right, and significantly higher
over oil. So, there were -- they -- they -- clearly,
there were some characteristics different about this
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January, this winter, than the last fourteen years.

And -- and then of course -- I'm --
yeah, I'm sorry. And then of course, it -- I -- I
hope it's obvious. Really at the point where the
Marcellus and Utica Shale discoveries were made and
the drilling happened and -- and all of this excess
inexpensive gas hit, that's where now, you finally
see a huge separation between gas and oil, starting
at about 2008, whereas the twenty or thirty years
before that, gas just kind of traded at ninety
percent of the oil price, which you can see on a --
the earlier part of the chart. Or, if you took this
to the 1990s and the 1980s, that's what you would
see.

So, we really -- you know, this is
just a good thing that the -- the -- the gas is so
much cheaper than oil for the last five or six years,
at least in total. Maybe not last January.

Okay. Trying to -- to beat that
yellow light or trying to beat that red light, the
preparation, the I.S.O. did do a lot to prepare for
this winter, so it -- we -- we -- we -- we were not
surprised. We spent a lot of time with fuel surveys,
with generators, talking to them about what kind of
gas service they had. Was it -- was it interruptible, was it quasi-interruptible, did they buy capacity releases?

Spent a lot of time with oil, like how much starting oil were they -- oil inventory did they have, a little or a lot, and if they only had a little, what were their replacement schedules and plans, with barges and trains and trucks. Put a lot of work in to that. It turns out, that was time well spent.

We always knew for a short duration cold snap, there's enough inventory onsite, to -- to keep things in -- in good shape from a reliability perspective. We always did know if it was a long sustained cold snap, we'd have to be involved watching this and -- and maybe helping generators manage this fuel with -- with bids, or with reliability commitments. And it turns out there was a -- a fair amount of that.

Each day, before the cold snap, we would get updated fuel inventory and gas nomination information from the generators. That was helpful to -- for us to manage reliability and come up with least-cost solutions.
And -- let's see. And then --

yeah, as I say, the very bottom little bullet, this
is important, toward the end of January, so now I'm
talking about like the third week of January, with
sustained cold snaps and now a forecast for it to
stay cold another whole week, the oil depletion
concerns led to increased I.S.O. efforts to manage
projected unit capability on alternative fuel. So
there was a lot more monitoring and managing
reliability, by picking where other types of fuel
resources were available at higher prices, so we
wouldn't run out of fuel at any of these locations.

The -- the next slide, the
operating performance and characteristics in early
January were different than late January. Early
January did seem to be characterized by a -- a
high-level of generator derates. And later on, I'll
talk about that's where we're trying to go with our
market design improvements.

On January 6th, we did have a
significant transmission cable trip and lock-out for
a couple of weeks. On January 7th, a very important
connection with Ontario trip, but fortunately came
back at lunch time. I'll talk about the -- the
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derates on another slide.

And as someone said earlier, we did activate demand response on January 7th, which was our peak winter day. We did do public appeals early in January and -- and issued a NERC emergency alert, one on January 7th, when we were very close to meeting reserve requirements.

Then the next slide is talking about the second half of January, which with a talking point, I'd say was more -- the -- the generator-outages or derates were not significant. But -- but with these longer sustained cold snaps, it was just tougher monitoring and managing the fuel and -- and generators were having trouble to keep up with the oil.

And what was interesting is in the past several many, many, many winters, gas has been the fuel of choice. Gas has been cheaper than oil. Generators try to maximize that and our market systems maximize that for a least-cost solution and then when there's a gap and the pipes are constrained, we just meet that with more expensive oil.

This winter was different for
twenty-two days in January in that oil was the fuel of choice and people -- we were trying to maximize oil. Our market systems were bringing on oil units. Generators' preference was to burn oil rather than gas. And then gas was used to make up the difference when -- when oil inventory became tight, so it was just a completely different characteristic in nature.

In the interest of time, we'll -- we'll go to the next slide. This is, quickly, the generator derates. These are, as defined, relative to after we made commitments for generators for the next day, to what the derates were in real-time operation, not to be confused with what was the amount of capacity that may be bid in the day ahead market and was not accepted. And there was a lot of generation committed that at -- a lot of gas units that would be at high gas prices, but our market systems chose the cheaper oil, bought on the oil, we met low with oil and reliability with oil and -- and actually didn't schedule gas.

But not counting the set that -- that wasn't even scheduled, this is the amount of derates that then were committed and then didn't make it.
Okay. I've got sixty seconds. Let me see.

I'll -- I do want to get the next steps. I do want to get the next steps.

CHAIR ZIBELMAN: Yeah. Yeah. We will -- we'll -- special dispensation.

MR. YEOMANS: Okay. All right.

Well, if I'm not going to be electrocuted --

CHAIR ZIBELMAN: We're running on time.

MR. YEOMANS: -- let me -- all right.

So, slide twelve, observations, these are the -- these are important. I said that.

This winter was characterized of many days of gas exceeding oil prices. And people ask me, Wes, were the generators able to get gas, and I, you know, for the dual fuel and I'd say well, I don't know, I don't think they were trying that hard.

If they had oil capability and dual fuel, they weren't trying to get expensive eighty-dollar gas. They were trying to burn their seventeen-dollar oil. And that made sense for customers, it made sense for reliability, and made
sense for the market systems.

And so, it resulted in high levels of the market system's economic scheduling and dispatch of oil-fired generators. As an example, the load weighted L.B.M.P.s for January, across New York State, were a hundred and eighty-three dollars a megawatt or eighteen cents a kilowatt. That was a hundred and seventy-six percent over the December electric prices, which were high.

But if you look at the gas prices, on average for the month, it could be -- Transco Zone Six, but it could be anything. It could be Tennessee; it could Algonquin. It -- they were all the same.

That was twenty-seven dollars. So, I mean, that's -- that's just a high gas price on a cold day. This was the average for the month of January, twenty-seven. And -- and so there's the average of the sixties and the eighties and one hundred, with a bunch of days at five and ten, still a very high average gas price.

So the gas prices were four hundred percent higher in January than December, but mercifully, the electric prices were less than half.
of that increase. Electric prices increased at less than half the natural gas prices.

Okay. Next slide, dual fuel observations for cold days, for short-duration cold days, so this would be a two or three-day cold snap, oil-fire generation was capable of receiving deliveries on a rate close to their burn rate or at least have enough starting inventory, even a small number at that. So, short duration cold weather events were fine. For longer, like two weeks or eleven days sustained cold, there were instances where delivery rates for oil could not keep with oil burns and for many days, oil was economic relative to gas. So, it's just the economic systems were running at full load and that was just a -- a -- a -- a difference in past Januarys.

Now, on to next steps, there's three categories of next steps. We have our -- a category of -- of improved coordination, our category of market design, and our category of planning and reliability.

Under improved coordination, we want to continue to improve our operator awareness of the fuel status of all generators and all fuels, in
addition to the approved awareness of pipeline conditions. The better our information is for reliability, the better and the least cost solutions we can come up with for managing reliability. So, it's just a matter of getting the best information, then we can make the best least cost solutions.

Continue the seasonal fuel assessment, improve the daily fuel monitoring, and then the -- the FERC is helping us with an order, last November, that really helps solve some of the confidential issues between the gas and electric industries, trading valuable reliability data.

The next bullet, request that O.F.O.s, or operational flow orders, are posted before the day ahead postings. The better information the gas generators can get, the better information they can get in their bid curves, the better their -- the more accurate their costs are on the bid curves, the better our day ahead marginal electric prices get -- can be or our market results.

Coordinate electric and gas infrastructure, maintenance outages. At this point in time, it's very important. We don't have a significant gas pipeline maintenance outage at the
same time as a significant electric transmission outage, so we're getting much better at working with the gas industry and coordinating these and not having two critical outages at the same time.

We're working with industry to develop gas balancing improvement and -- and a lot of this is going on with the recent FERC NOPR. And then promote R.T.O.-like services in the gas industry, in the areas of improved gas transportation service transparency, so that generators can see what is available on the pipes, and what are the different ways they could schedule to get gas in a more transparent way, and what -- anything that can be done to make the gas apply more liquid. It is a very large bilateral market today. There are some trading platforms, but we greatly support and promote anything that can be done to get the gas supply to be more liquid for the New York generators.

Next slide, markets explore potential market rule changes, to better value fuel assurance. The two areas of concerns we have are significant generator derates, as we saw in early January, and then limited fuel supplies during long, sustained cold periods.
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So, we're looking at just tweaks to our market design that better value the good performance and less value the poor performance. And in the long run, this should have a good -- a lower cost out -- outcome for customers, if we can really just keep -- keep the good units -- encourage those to stay online and perform. And it just ends up in a -- in a better market result.

The next bullet, consider improvements to allow generators to more accurately reflect their fuel supply constraints in the day ahead bids because the day ahead market just has a better opportunity to come up with a least cost solution than if you give that bad information and then have to solve it in real time.

And then the third bullet, coordinate with P.J.M. and I.S.O. New England, if either R.T.O. considers modifications to their energy bid cap offers.

And then the last slide, and I'm sorry I went over, in the areas of planning and reliability, and I -- I -- I -- I think Commissioner Brown mentioned this, this is probably the most important thing. And that is really, what's going to
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What's going to happen in MISO the next couple years?

It's definite that Vermont Yankee and Nuclear Facility in New England is going to be off-line December 1st of this year. They have another five hundred megawatts of -- of non-gas in New England retiring, so they have another twelve hundred megawatt gap just to the east of New York. And so those things are definite. But -- but even the -- the -- the E.P.A. mercury MATS emissions requirements will hit May 1st of 2015. And that could have a seven to nine thousand megawatt impact on coal retirements in P.J.M.

So, as -- as Commissioner Brown mentioned, it's important we do this regional study and not just look at New York and say what are the implications of the regional changes. And because if seven thousand megawatts of new gas-fired generators in P.J.M. are going to compete with the -- that scarce gas pipeline transportation system, that will have implications in New York.

And so, I think with that, I'll -- I'll conclude and I think there'll be questions later.
Sorry I went over.

CHAIR ZIBELMAN: Thank you. Thank you.

And then our next speaker is Mr. Wesley from NYSETRA. Thank you and welcome.

MR. WESLEY: Thank you very much.

NYSETRA appreciates the opportunity to address the Commission.

NYSETRA monitors heating fuel supply dynamics on a continuous basis throughout the -- the winter season. Specific to this application with natural gas, is the distillate fuel family, which includes ultra-low sulfur diesel fuel, heating oil. New York is the only state in the country using ultra-low sulfur fuel. That's a fifteen part per million fuel, ultra-low sulfur kerosene, and then the residual fuel family, number six fuel often referred to, various sulfur contents.

I will discuss the interaction of the petroleum supply industry with the natural gas industry, as a back-up fuel supporting natural gas interruptions.

This first slide you're looking at is distillate demand and it shows the historical perspective to -- to frame where we are today. Fifty
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years of -- of data on that slide, you can see that we peaked on a -- in the whole distillate fuel family for all the economic sectors, peaked in 1973. The most recent data we have is 2012 and it's about fifty percent down from that time period.

More importantly, in the residential sector, and that's the -- the light blue sector you see there, demand has come down about sixty-five percent. The net effect of all of this is a reduction in the amount of the industry, storage facilities, pipeline facilities, trucking capacity, distribution equipment used to distribute the fuel from where we were so many years ago. Next slide.

Similarly, in residual fuel, you're looking at, again, a fifty-year timeframe here. Back in '72 in New York, the electric system had quite a number of large capacity residual fuel burning facilities. In '73, we peaked at a hundred and sixty-nine million barrels. We're down like ninety-one percent from that time period to where we are today.

The green area you see on that slide is the electric sector. One of the -- one of the take-aways from this particular slide is what is
the petroleum industry, the supply industry thinking, as they look at this type of slide. And they're thinking this is a business that's going away, I have no reason to invest in the facilities to store fuels that no one is really using.

And lack of steady, consistent demand tells the big supply industry, there's no reason to commit facilities for this, there's no reason for me to stockpile inventories. Someone comes and has a contract and say I will need a specific amount of fuel, that's fine. I'll dedicate fuel capacity to this, storage capacity. But if it's a just maybe we'll show up and maybe we won't show up, this is not going to happen. And you can just see the enormous decline in -- in demand for the residual fuels. Next slide.

Taking a -- a little bit closer look at this, these are the -- these -- these two slides show the petroleum fuels used by the electric sector. The red is the -- the distillate family, home heating oil perhaps, ultra-low sulfur kerosene, ultra-lower sulfur diesel fuels.

You have a fifty-year slide on your left. If you move over to the right slide, I've
taken the same and just took a look at that quick little, last twelve years. The peak occurs in 2005, which is actually a hurricane impact year. That's the year that hurricanes came ashore, tore up the Gulf Coast gas distribution and processing systems. And the -- we used a lot of residual fuel in the fall of that year as we waited for the gas distribution and supply systems to recover. But you can see, over the last three or four years, there's just been no demand, at all, by the electric sector. Next slide.

Refining capacity in the northeast, this is a cluster of refineries just south of us. They're in New Jersey, they're in Delaware, and they're in Pennsylvania. Again, this is going away. It's not economic, for a number of refineries to operate. They've closed. I can think of three in the last roughly twelve years that closed and went away. So, our capacity to produce refined products moved from one point seven million barrels a day, down to one point three million barrels a day.

These refineries are concentrating on gasoline and diesel fuel. That's where the money is. That's where the three hundred and sixty-five day a year demand is. This is what they work on.
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Replacing these facilities, when these refineries are taken out of service, their parts are sold or cannibalized or whatever occurs to them, they have been turned into import terminals.
The tankage is still there in many applications, but they don't have the ability to manufacture the fuel -- make as much of the fuel that we use, so as a result, our fuel is coming ever farther away, United States Gulf Coast and from European or world markets.

Next slide.

This slide illustrates this.

You're at -- you're looking at where does our fuel come from. The blue on the bottom is the east coast production, the red are imports, and the green is from other pads. And generally what I'm referring to there is the Gulf of Mexico production area.

And -- and you can see, let me catch up with you, that we're down to about one-third of our supply that we use for distillate fuel oil, all those heating oils and kerosenes is coming from our local markets. We have less response capacity, locally, than we had a number of years ago.

We are dependent on economic signals to world markets, the Gulf Coast, to bring fuel to us, as
needed. So, when there's a serious increase in
demand, as a result of cold temperatures, then that
effect is the market says, with price signals, we
need more fuel.

Unfortunately, this fuel is three
to four weeks away. This is the time period it takes
to secure capacity, to bring fuels back to the
northeast. So, we've lost some resiliency here.
We've lost the ability to respond rapidly to
immediate needs.

Again, here's your picture of
historic distillate inventories. We're looking at
from 1998 through the current year. The color
sequence you see is -- the green is home heating oil,
high-sulfur fuels.

The red is a five hundred part per
million diesel fuel, which is what the transportation
sector would have been using during those time
periods. Regulations pushed that down to fifteen
part per million, that's the blue. You can see when
that occurred. What is that -- what you're actually
seeing here is that red -- that initial red is the
on-road diesel fuel that we would have been using.

What I'm trying to say here is if
you draw a line for just pure diesel transportation need, it's about ten million barrels. You draw that across, there was almost nothing in storage, a very limited amount of storage capacity, in -- in January 2014, early December, that type of time period, compared to what we had many, many -- as recently as two years previous. Next slide, please.

This chart illustrates all of this. On the left, you have twelve months leading up into, you know, the winter season. And you can see that we are forty-five -- excuse me -- forty-three percent below the five-year average on inventories ready to go during -- during a winter. This is what the industry was doing. It wasn't getting an economic signal to store more fuel.

The chart on the right shows that leading into the season, it's August and September, we actually had pretty good volumes of fuel. But again, the economic signal was future prices were more costly than the fuel I had in inventory, so as we entered the heating season, the economic signal was use the fuel in storage. And we did.

And then, when the cold weather hit, that Wes was referring to, our inventories
really were in no good shape to handle this. You
couple that with regular consumers, the normal
customers for the heating oil world, increasing their
demand because it's cold, you have gas interruptions
at the temperature controlled level, you have
economic viability activity by the electric sector,
everybody's just pounding on -- on inventories. Next
slide.

Residual fuel, try to catch up with
this. This is the refinery output of residual fuel
in the northeast. It's gone from roughly two hundred
thousand barrels a day, as recently as maybe
ninety-eight, down to fifty-seven thousand barrels a
day. There's just not any residual production of any
magnitude occurring on the east coast.

One of the problems with these data
sets, we can't tell you the sulfur content of what
the fuel coming out of these refineries are. I don't
know if it's point three, New York State -- excuse
me -- New York City or, as you move away from New
York City, the sulfur limitations increase. It's a
visual we don't know. So, if you have electric gens
in New York City looking for more fuel, I'm not sure
we're producing any of this. Next slide.
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Again, this is illustrative of --
just like the heating oil, the -- the -- the residual
inventories were nowhere near where they had been,
over the last ten years. They were just a -- just
significantly lower.

And I think I have one more slide.

Nope. That's it.

Essentially, what's going on here
is this industry is shrinking, simply because lack of
demand, lack of capacity. Where we were ten -- as
early as -- recently as ten years ago is just so much
less than where we are today. And the ability to
respond to economic activity is just much more
limited than it ever was.

CHAIR ZIBELMAN: Thank you.

Let me just -- because of the size
of this panel, maybe we'll just ask a couple
questions because I'm concerned that -- by the time
we get through the end of the panel.

But Charles, and this is just sort
of what -- what you were just leaving off with and
what you heard Wes say. It's kind of a nice --
Charles Wesley and Wesley Yeomans.

MR. WESLEY: We tag team.
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CHAIR ZIBELMAN: That's very good.

So, would -- would some of the things that -- that -- that Wes is talking about of -- about requiring generators to maintain fuel, would that address some of your concerns about creating a better demand signal?

MR. WESLEY: Yes, it would. The -- the -- there's nothing like having physical capacity, physical fuel in storage. It allows the market to digest a little bit better during periods of extreme demand.

You know, we don't practice this very much. The last time we had significant cold temperatures, five, six, ten years ago, whatever it might have been, there's just no economic signal here to the petroleum supply system, to do anything. It's like they never call. And -- and they have just such a limited capacity when it does call. All the economic signals go out, but the response is a month away. It's just -- so activity to prepare, have a storage, would be a beneficial -- a beneficial thing.

CHAIR ZIBELMAN: And do you -- you want to comment, Wes?

MR. YEOMANS: Yeah. I'll just
quickly say yeah -- yeah, I can appreciate. I mean, if you have eleven out of twelve months, gas is significantly lower than oil, you know, the oil -- the economics aren't there for oil, eleven out of twelve months of the year. Then one month of the year the economics are way in there, so that just makes it tough for the big guys as to how many refineries they got to have.

Part -- part -- part of the solution may be -- is, rather than this just-in-time delivery strategy from the generators, which says gee, let's not buy and hold a lot of it for ten months, let's just get on the phone and buy it quickly in January when we need it. To -- to Charlie's point, if the refinery capability isn't there, it's just tough to come up with that, as -- as opposed to, you know, generators have storage and can buy a little bit in April, a little bit in May, little bit in June, as the small number of refineries can produce it, and then have a significant amount of inventory going into the winter, that -- that -- that's a -- an approach to try to solve this problem.

CHAIR ZIBELMAN: And my -- my follow-up question -- and by the way, for the rest of
the panel, this is -- you're talking, if you want to comment on -- on these, please -- please feel free because I know these are important issues.

You know, I -- I think as Commissioner Brown noted and -- and -- and as you noted, Wes, this was a -- not just a New York issue, this was a national issue, a regional issue. And it's potentially an issue that's going to get worse as we see more non-gas retirements and also, just -- just increased pressure then on -- on the pipeline.

Here's my -- here's my -- it's more -- I think it's an observation. It's also a question. I'd be kind of interested hearing everyone's response. So, here we are in New York, requiring the dual fuel capability in the city. You indicated it's not required in New England. And we are seeing gas generators coming on. Aren't we in a potential risk situation of you're going to have more pipeline demand, but if we, in New York, continue to look at dual fuel capability from a liability, which means in a -- in a way, aren't we then backstopping our regional neighbors who may not require that, because now we're fighting for gas scarcity? And we're -- and if we, as you say, monetize the value of
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this inventory, we're effectively raising prices in New York, to provide a better reliability backstop for New England, P.J. and others; right?

Is that -- am I understanding this right?

MR. WESLEY: From -- from a fuel's perspective, yes.

MR. YEOMANS: Yeah. I just want to understand. I -- I'm not sure requiring some -- some oil inventory is going to raise prices. Hopefully then the economic process will --

CHAIR ZIBELMAN: Well, but what --

MR. YEOMANS: -- then 20:31:03.

CHAIR ZIBELMAN: -- I'm saying is -- is that what will raise prices is that if there's gas pipeline scarcity and we're able to maintain -- reduce that pressure because we have dual fuel units that are being dispatched, essentially our dual fuel units are supporting P.J.M. and the New England, as well, who may not have that same requirement, so therefore, their customers are not bearing those costs.

MR. YEOMANS: Yeah, that may be.

If you think about the market system, when we compare
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our price to P.J.M. price for scheduling interchange,
and our price to New England, yeah, I -- I think that
is -- that would be a 20:31:36.

CHAIR ZIBELMAN: Okay. And then
we'll have --.

MS. BLOODWORTH: Can I -- can I
answer one thing?

CHAIR ZIBELMAN: Sure.

MS. BLOODWORTH: This is Michelle
Bloodworth, with America's Gas Alliance.

I think I'm on. Am I on? Can you
guys hear me? I know you can hear my southern
accent.

CHAIR ZIBELMAN: I haven't noticed.

MS. BLOODWORTH: Well, I'll try to
tone it down, as my taxi driver told me.

One thing, on the flip-side,
though, I would think about is there's a lot of
discussion related to the retirement of -- of older
coal and -- and even some nuclear plants. And
although we support fuel diversity, I would also look
at it as -- as you look at what's needed to build new
infrastructure, to get more firm capacity, to take
advantage of all this prolific natural gas, the more
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those units are run, the more it also justifies the cost.

So, I think you need to look at both sides, the cost of mechanisms and market rules, within New York ISO, to allow that recovery because once those units operate more in base load capacity, you're amortizing that cost for that infrastructure over a lot more volume, so that cost goes down.

I just think you have to look at it as a portfolio of options versus one versus the other.

CHAIR ZIBELMAN: Sure.

MS. BLOODWORTH: Thank you.

CHAIR ZIBELMAN: No; I -- I agree.

Is there any -- I have to -- we have --

COMMISSIONER BROWN: Just one more question.

CHAIR ZIBELMAN: -- and then I -- I may have more, but I just feel -- go ahead, Garry.

COMMISSIONER BROWN: Just one question for Charlie, who has gotten really smart over the last thirty years.

Did -- was there ever a time where
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somebody couldn't get delivery?

You said man it's tight, man the inventories are

slim, man it was really -- we're right on the edge.

Were there instances where people said I need it and

ty they said no can do?

MR. YEOMANS: Yeah. This -- this

past winter, some west generators had difficulty

getting the specific quantity at -- and -- and sulfur

content fuel they -- they needed. Okay? And on the

distillate side of the -- of the family, on a -- on a

regular daily basis, I had terminals -- I was in

contact with terminals -- heating oil terminals that

were saying I'm dry, Charlie.

Now, they had scheduled another

supply activity, in some way, shape, or form, whether

it was a pipeline delivery that was anticipated

and -- and it would have arrived, or a barge was

coming in, in a couple of days or something. But we

had numerous instances where, in the downstate

market, specifically, home heating oil distribution

companies were short-loading their homeowners.

And -- and maybe you needed two hundred gallons, you

get a hundred gallons and -- and then you're

revisited again later on.
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But yeah, this -- this occurred this past winter.

CHAIR ZIBELMAN: And one more for Wes, because I know I'll forget this. But I really -- I'm fascinated by, actually, the two slides of your showing the price increases and Raj's earlier slide, showing the correlation between the price changes separation and exports into New England, I think it would have been at that point, or P.J.M.

First of all, when -- when New York I.S.O., when we do this import/export, typically it could because of a price and sometime it's because what -- in these situations, there could be one of our neighbors are into a reserve requirement and there's a NERC requirement, an agreement that when one -- one region is having problems, the other region will help them out. And -- and I know that was going on this -- this past winter. Is that correct?

MR. YEOMANS: It -- yes.

CHAIR ZIBELMAN: So -- so --

MR. YEOMANS: Yeah.

CHAIR ZIBELMAN: -- but how -- are you looking into -- because it's an interesting
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question. If -- if because of transmission constraints and in the dispatch protocol, when we export to New England, if that is a cause of these price separations, in a way -- is there a way that -- to make sure that the potential costs that are being imposed on the Capital Region can be recovered by the Capital Region consumers, who essentially are bearing the brunt of -- of this type of situation, are there any market mechanisms to reallocate when you -- when you have this type of separation, if you can show a cause and effect? Because it's a form of mitigation, in a way.

MR. YEOMANS: Well, yeah. Two comments. I -- I just would be a little careful of the cause and effect. It is --.

CHAIR ZIBELMAN: Well, that's a -- that was -- yeah, and I don't know, so maybe you want to --.

MR. YEOMANS: So, let me start with that and then I'll move on to the -- the -- the -- whatever that billing question was, but -- or that allocation question.

You -- you know, I -- -- so let me just think about what Raj's chart -- he had one that
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said hey, when the -- the exports to New England, the volume of megawatts increased, it appears the price difference between A and F increased. It -- it's hard to know. That may have been happening anyways.

If -- if transmission is scarce from Buffalo to Albany and pipeline is scarce between Buffalo and Albany, we -- we're getting that price separation for -- for a set of reasons that -- that -- that are correct and make sense.

Now -- now, if New England's one dollar higher, then the -- the market systems are going to schedule, you know, from low cost to high cost. So, if New England's one dollar higher than Albany, you know, you'd start to see the megawatt exports start to go.

It -- it is true that -- that that starts to look like load from supply and demand perspective, east of central east, when you're exporting to New England, that starts to look like load. But I'm not -- I'm not convinced that's the large driver to the water price separation, between Buffalo and Albany.

I think we already had that price separation; it might have increased it a little bit.
But in other words, if you were to cancel those deliveries of -- and let's say it's a thousand megawatts, that's a thousand megawatts less than the east, the -- the marginal price in Albany would drop a little bit, but I don't think it would come down to the Buffalo price or it wouldn't be the majority of that price. But -- I mean, I don't know. Somebody'd have to go up and study that. So, I'm -- I'm not positive there's a strong cause and effect.

But the -- the more important point is, you know, that -- that is how markets work and that's markets working. And the converse example is Hydro Quebec and Ontario. I mean, if we have a higher price than Ontario and -- and we have a higher price than Quebec, then these market systems that are working on all four scenes, what -- whatever those markets are doing between us and New England, they're doing the same thing, but to our benefit, between Quebec and New England.

So, if -- if our marginal price is higher than Quebec, the market systems schedule some gigantic imports in the -- to New York State, which reduce prices. And they -- they import from Ontario on our two sets of connections and that -- that
reduces prices. And if you take, over the course of the year, the time some areas are scarce and others aren't and some are long or some are short, and, you know, one day maybe we're exporting to New England and it raises an Albany price, there's another day where we're short and somebody else isn't and it's coming the other way. And over the course of a year, or a decade, you know, those four interactions really come up with a lease cost solution for customers.

CHAIR ZIBELMAN: Thank you.

Okay. We'll -- we'll move on. Mr. Parisi?

COMMISSIONER BURMAN: Actually, I just have --.

CHAIR ZIBELMAN: Thank you.

Oh, do you have a question?

COMMISSIONER BURMAN: Yes.

CHAIR ZIBELMAN: I'm sorry.

COMMISSIONER BURMAN: I'm sorry.

I -- I've been listening a lot today and I just kind of wanted to follow up with a question, Mr. Wesley. You made a statement and I just wanted to make sure I understood it. You said that the industry was shrinking. And -- and did -- did I understand right, simply because the lack of demand
or the lack of capacity? Is that what I understood you to say?

MR. WESLEY: The -- the -- the fuels that we're talking about in this application is residual fuel and the distillate fuel family. And yes, that industry is -- is shrinking in size. The amount of fuel being distributed, running through their systems, for -- for a -- a great number of reasons. Consequently, the infrastructure that the industry uses -- the petroleum supply industry uses to manage their fuel is -- is much less than it was.

COMMISSIONER BURMAN: Uh-huh.

MR. WESLEY: And it -- it's naturally shrinking, also, in -- in lock-step with demand.

However, when you reach a point in time, where you have -- for some -- in this -- in this application, it was a number of polar vortexes, you have a huge spike in demand. Electric sector, residential sector, commercial demand, it's just everybody needs these fuels to heat.

The industry has lost the capacity, or is losing the capacity to respond to these spikes, simply because they don't occur often enough to make
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the investments necessary to support that. And we end up in a situation where you have a reduced capacity, trying to meet all of this demand. It's an abnormal amount of demand, but it's still a legitimate demand.

How would you manage that? And one of the aspects you can manage that with is greater levels of inventory, by whomever the participants are that need this fuel. There's an economic -- a -- there's an economic penalty there, if -- if they don't need it, too.

COMMISSIONER BURMAN: Okay. Thank you.

I just would like other folks to comment on it, during their presentations or, you know, later with comments just because my question really is related to, you know, what is the driver of what else might be causing that lack of demand or lack of capacity that we, as a state, might be contributing to.

And then the second question is you had made a comment, I believe, that we didn't know what the sulfur content was. Can you expand upon that?
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MR. WESLEY: Sure. In the residual fuel family, by itself, there are different sulfur requirements for different geographic locations in New York State. In New York City, if you're burning residual fuel, it's point three percent. As you move away from New York City, it expands a little bit.

The data that we have, and it's Energy Information Administration data from Washington, clusters all of the residual reduction, inventories, imports, just the whole package of information as one thing, residual fuel. So, you don't know how much of the fuel you would need, for example, to assist New York City specific generators.

You -- the -- I could tell you the inventories are five million barrels in the -- in the mid-Atlantic region. There -- there might literally be nothing of point three. It might be surpassing that level. There's just no clarification in the published data, from E.I.A.

The utilities themselves -- or excuse me -- the generators themselves would know what they need. And the companies may have that -- the companies have that in -- in their storage tanks, if they have any, but it's just not published for us,
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the analysts, to see that information.

MR. ROONEY: Commissioner Burman,

some of the issues and questions that have been
raised here are going to be covered in my
presentation --

COMMISSIONER BURMAN: Okay.

Thanks. I'm glad I teed it up --

MR. ROONEY: -- when we get there.

COMMISSIONER BURMAN: -- for you

then. Thank you.

CHAIR ZIBELMAN: So, just let me

note something.

We have -- it's a quarter to

twelve. We said that this panel would be over at
twelve, but it's not going to be over at twelve. So
I want to make sure that all the panelists have
adequate --

COMMISSIONER BROWN: Twelve thirty.

CHAIR ZIBELMAN: Twelve-thirty?

Okay. Then we should be good.

COMMISSIONER BURMAN: We'll --.

CHAIR ZIBELMAN: But just so --

we -- we do want to make sure people have enough
time.
COMMISSIONER BURMAN: Yeah. And --

and I -- just on the sulfur content, because I know
over the years, there have been a lot of concerns
about -- with requirements on lowering the sulfur
content, whether or not the state was actually
harming -- you know, putting ourselves at harm,
economically with that. And so that's why, for me,
this raises an issue. And that's why I'm just
concerned with what have we done. You know, and so
that's why you were saying us not -- I mean, not
knowing what is the -- the sulfur content raised a
red flag to me. So, thanks.

CHAIR ZIBELMAN: Thanks,

Commissioner Burman.

So we'll move on to Mr. Parisi.

Thank you.

MR. PARISI: Thank you for having
me here today.

So, my role with Con Edison, we
work in the transmission reliability business, as
well as on distribution end. I'll talk mostly about
the transmission end of it. It goes very much in
line with -- with -- with -- with what NYISO has
mentioned already, also in the oil industry. I think
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it'll fill in some of the gaps that the -- the questions had come about, because we certainly saw many of these instances firsthand, directly talking with generating facilities.

If we could, the first slide?

Just very quick recap. You know, so my perspective is looking at Zone J, New York City area. All of our information comes, basically, you know, certain -- centered around Central Park.

That's where we take our weather information from.

I don't want to be redundant, but, you know, low temperatures -- low temperatures throughout the winter period, January 7th being the -- our big day, that was the lowest temperature, four degrees, lowest since 1896. This winter, we saw thirteen days with snowfall above one inch and -- but it doesn't sound like a lot to the people in Albany. Downstate in New York, anything over one inch is cause for concern.

The Department of Sanitation actually -- in monitoring the data that we get back from New York City Department of Sanitation, spread four hundred and fifty-six thousand tons of salt, which does quite a bit of extensive damage to
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infrastructure in New York City, primarily on a
distribution system. So, you know, mostly throughout
the wintertime, we're addressing, you know, concern
with the secondary system, as well as primary
feeders. High salt definitely drives impact.

The winter, 2013-2014, December
not -- not a terrible month. January and February,
that's our big two months with temperatures below
average. Even though -- you know, even when it says
below average of four degrees or three -- three --
three degrees, you know, those are average numbers.
You throw a couple of sixty-degree days in there, and
those stretches where we -- where we were down low,
you know, that sort of makes it look like it's not
quite as bad as it was. But the -- the cold
stretches that we saw were very impactful.

And obviously, you see the snow
totals down below. These are, you know, up there in
the top ten snowiest Januarys -- Januarys and
Februarys that we've had. Next slide.

Winter peak, Wes mentioned it
before. Our -- we hit our winter peak on January
7th, in line with the NYISO's winter peak and
obviously, very far down from our summer peak, but,
you know, there was -- with generation available, not really, you know, no real forced outages, but the fuel concern was -- was the biggest battle for us all winter, during January and February.

Overall, the electric system performed very well, the transmission system and the distribution system. The equipment breakers and substation equipment had no significant issues, work we've done to reduce S.F. six leakage and air compressor issues, paid dividends very much. We really had no impact that drove transmission feeder outages or anything like that. It just -- the equipment held up very well, through very cold circumstances.

We had proactive discussions throughout the periods with NYISO, as well as our Con Ed gas control and -- and -- and daily conversation -- daily communication, even more than -- more than daily, with our Zone J power plants. This is very much in line with what our -- our folks at -- what -- what Charles had just mentioned, as far as the oil industry.

Dual fuel -- fuel burning capability was a tremendous asset to us. Within the
city area, primarily -- basically everybody does have
dual fuel burning capability. That made us very
flexible, which was good for a couple of days. When
cold stretches turned into week-long and
two-week-long and month-long stretches, that's where
inventory really began -- started to see the effects.

We also saw, initially -- very
initially, infrequency of use of fuel oil. You know,
the last three winters, you don't -- you don't use
the oil burning capability, nearly as much. Many
facilities took a little bit of a -- because there's
an infrequent evolution to get equipment, you know,
up and going, oil-wise and -- and be more reliable,
you know, a little bit of a learning curve to get
back -- back in the groove of burning oil.

But we did see, barging
limitations, fuel availability limitations, talked to
many generating stations who said that their delivery
was twenty to twenty-five days out. So we were
managing those inventories across our service
territory, quite readily.

We, along with the NYISO,
implemented weather protocols. We closely monitored
predicted weather. We adjusted staffing throughout
our transmission stations, to make sure, for these long cold stretches, as well as weather impact that was coming in, that we had people in place that could respond in the event that anything did open and had to be put back.

We restricted scheduled work to prevent contingencies. We did not -- they were -- when we saw weather coming in, temp -- either temperature or precipitation, we did cut back on schedule work that would affect the transmission system that could lead to congestion or put us in a contingency situation.

Obviously, very high natural gas demand. The generators -- gas deliveries were not interrupted. They did not -- there weren't days where they couldn't get gas, but obviously the price, in many cases, precluded doing that.

Oil was the more economical fuel for twenty-seven days. I think that compares almost in line with what Wes had mentioned. Most of that was -- I think it was twenty-one days or twenty-two, fell in January.

We tracked -- we tracked the fuel supplies of our -- the generators within our service
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territory, very closely. More so than ever in the past.

Regular calls daily to gen-stations, gaging what their fuel burn rate was, how long they expected to, you know, be available for the amount that they had, and when their next delivery was coming. And -- and I know Wes was doing that, as well, from NYISO. I think -- I think we drove the generators crazy throughout the period.

So, we closely, also monitored our min oil burn requirements, which obviously in January didn't really matter too much, because they were already burning oil, but when we get into high gas volume days, we do -- we do maintain a min oil burn requirement, so that in the event that there's a -- a gas loss, immediately we don't have a unit that trips or, you know, a load rejection of any kind.

Some G.T.s were unavailable to the system, either through gas prices just being not able to be secured, or also oil burning not being able to be performed.

The liquid fuel challenges in late January. So this is where, you know, I think we can back -- we can support what you've heard before.
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We saw -- we saw reports of barges being available with point three five percent sulfur, which couldn't be used. Other generating stations, where they -- they did actually come off and not available the next day, because there was no fuel on hand. There was certainly barging limitations. We -- we've certainly seen over the last few years that the amount of oil usage, as it has declined, the people that are in the business, the infrastructure that surrounds the industry, has really diminished along with it, inventory of tanks, barging availability.

Some of the new units that are in our service territory that are, you know, gas turbines, combined cycle, they just don't have the oil tank storage on site. They weren't built that way. It was -- it was put to, you know, basically to have a day or two tank on site, which would get them through a cold -- you know, a -- a couple days, where there would be a -- cold weather, but not to the extent where it would be weeks, which is what we -- which is what we were up against.

For CECONY, for our own company, we have the steam system. I'll just go through that really quickly.
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We didn't have any issues with the steam system alerts or reserves. We had to have very close coordination on gas. We had our own fuel concerns that -- primarily though, because we do -- we do burn oil every winter, it -- you know, it's our regular preseason checks, it's the -- the -- the plants that were built, you know, previous to the new generation and some of them that have come up -- that have come on, on a combined cycle.

So, the inventory facilities are there. So it was just a matter of getting the barge deliveries and keeping up, which -- which we were able to do. In fact, we were able to also, in -- in some cases, support and, you know, route some people to barging facilities that could help out some of the generators that were looking for fuel. And it's -- so the kind of system -- steam system did very well.

Along the lines of what we -- what Wes was talking about, fuel oil inventory, I think, you know, we could probably benefit by doing more of it electronically, reporting in, knowing what people have for us. Some weekly projections, even demonstrating maybe more so, preseason activities, demonstrating capability on liquid fuel use, the
ability to auto-swap, which is very important, and the seasonal fuel supply and available inventory, which I think Wes has mentioned, you know, better more reinforcement with -- with securing what people have on hand and what we can count on and for.

That's it.

CHAIR ZIBELMAN: Thank you.

MS. MADEA: Thank you. Welcome.

So, just background on energy first, we have fifty-three thousand megawatts across --.

COMMISSIONER BROWN: Get a little closer to the mic, please?

MS. MADEA: Oh, sorry. How about this?

Fifty-three thousand megawatts across the country, it's a diverse fuel mix of renewables and coal, oil, natural gas. And a -- a lot of that is utility scale and some is small scale distributed generation, as well. And in addition, we have a demand-response company that participates in New York and about three million retail customers.
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throughout the country.

In New York specifically, we have about four thousand megawatts. Two of those units are dual fuel units and one of those is a sixteen hundred megawatt oil facility.

Overall, the winter -- our -- the -- the system worked very well. I think what -- what we've been hearing is that the -- the -- kind of the cracks in the system that have been pointed out are that what -- there's a desire for a higher level of reliability, but that's not what the market's incenting right now. And so I think that's kind of the -- the struggles that we've been hearing.

And the market's working to attract the least -- the more efficient least cost generation, but there's needs for fuel diversity and storage, that to -- to address this risk of just-in-time delivery. And so, diversity is critical to keeping the lights on. We heard about the oil units running and the natural gas curtailments and high natural gas costs led to the unprecedented run times for the oil -- for the oil units.

So, our -- our pre-winter preparations worked very well. We built up the fuel
inventories. And we had -- were fortunate enough to have a -- our employees for the -- the regions that weren't impacted a great deal by the cold snap, to come out east and help the facilities there. And that worked really well. And we had senior staff positioned at all of the plants, as well, too.

And our plants were operating under what we call our -- our COMA provisions, which is our conservative operation and maintenance alerts, which means they can't do any operation or maintenance on the plants that are likely to cause an impact to the plant, without senior approval. And none of our New York units ran out of fuel during the winter -- during the winter snap.

Just some of the numbers for you, I thought these were interesting. So, overall our facilities burned over one point one million barrels of liquid fuel, in January 2014. And that is greater than the eight thousand barrels in -- that were burned in all of 2013. And in just looking at New York, we burned approximately eight point five million gallons of liquid fuel, at the three units I mentioned, in -- in January '14, as compared to seven point five million, in all of 2013 again.
And one of the -- one of the challenges we have was replenishment at our Astoria facility, in New York City. And in terms of the truck deliveries, in the cold snap, we had a hundred sixty-eight trucks of liquid fuel delivered, versus ninety-two trucks in all of 2013. And so that's one of the challenges we saw, in just getting the trucks into that facility.

So, this is, again, a repeated theme in terms of infrastructure. So, our -- our biggest challenges are the infrastructure of the oil system. And it's the lack of the barges, the lack of the trucking capacity, availability of the drivers. And during the cold snap, we were in constant communication with the states and with the Federal Department of Transportation, in order to get waivers of the trucking regulations to get the -- the -- the trucks into the plants. And we put -- some out-of-town truckers, put them up in hotels near our plants, so that they would be available to deliver.

The -- the one specific situation, for example, our Oswego facility, it -- now that -- we've talked before about the -- the sulfur requirements and since those sulfur requirements
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dropped, we used to get that oil from Canada and just barge it down. But they don't have the low-sulfur fuel that we need and so that has to come from the east coast.

What we do is we have to find it along the east coast, get a -- get a vessel, take it up to Canada, position it up there, and then get the smaller vessels to bring it down to Oswego. And this is a multi-month process that we've been looking at. And so right now, we're in the process of replenishing Oswego and, obviously, those barges -- it's now up in Canada, but those barges have other obligations and so we're now trying to get the vessels to get it back down.

But this is what was being said before, about even if you know you need it, it's going to take us multiple months to get it at this point.

CHAIR ZIBELMAN: Were -- were you going to -- just so I -- why do you have to go to Canada to get it back down?

MS. MADEA: Because of where -- where it's located, it's -- it's in Oswego and so it has to be barged down. So, the -- so, the only place
you can bring it down from is Canada. If you bring it up, you can't get it in, essentially.

CHAIR ZIBELMAN: I guess I admitted I'm not a native New Yorker. Okay. Thank you.

MS. MADEA: I asked the same question.

COMMISSIONER BROWN: Lake Ontario.

MS. MADEA: Yes. So overall, the -- the oil issues that we've been seeing. So the -- the fuel cost is high, the inventory -- inventory turnover is low, one of our plants, this winter, the Bowline facility was burning 2007 oil that was in its tanks. It's hard for us to predict the necessary levels of oil that are needed and the utilization of the oil-fired capacity is really high during these narrow windows that we've seen.

And not all dual fuel units are created equal. This is something that was touched upon, too. The modern dual fuel units have the high environmental permitting requirements and the tight run-time limitations. And so, as a result, this storage is sized accordingly. And so those aren't the units that can support winter periods like this. And then in terms of the older dual fuel units, while
they have the storage capacity, the issue there is that they have low capacity factors and so the system -- the market to support the running of those facilities has gone away.

So overall, in terms of kind of what we can do to create this issue, so just to highlight what we talked about and what Commissioner Burman mentioned before is that the -- the current wholesale electric markets don't support the large capital investment that's necessary, in order to develop or retain these large quantities of storage. And the newly permitted dual fuel units have limited operating hours on fuel and often even smaller onsite liquid storage.

And the fuel diversity that's needed and the infrastructure for the resupply of this liquids, is no longer in place. So, while one example was the I.S.O. New England fuel inventory program that they did last year, and while it's an out-of-market solution, it worked in order to get those storage tanks stocked with oil. And so we -- we need some sort of a market mechanism to allow for cost recovery, to incent these older units to -- to keep their inventories up. And it's some sort of --
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one thing that we were discussing is some sort of market product that could encourage the dual fuel units to continue operation, some sort of an ancillary service that would offer additional payments for it.

And I think one -- another thing is that any market design changes that penalize the oil, or the older dual fuel units, that will work to counter the incentive to keep these units running. So, I think that's a -- that's something to be cognizant of, going forward.

And the other thing is, in terms of just the natural gas package, one thing that would help is we've talked about this elsewhere a great deal, is how it trades as a weekend package. If that package would be split up, it would just help in terms of -- in terms of pricing.

Another thing that was talk -- talked about here, is whether any new pipeline infrastructure and a -- and transmission, or how that's going to work. And I think our position on all that is what -- if we find out there's a need for something, it should be a competitive process and we shouldn't automatically go and start building
pipeline, without considering storage and distributed
generation and other possibilities, and see how those
all equate.

So, I think that's -- that's all I
have.

CHAIR ZIBELMAN: Thank you.

Mr. Truxell, welcome.

MR. TRUXWELL: Thank you. I'd like
to thank the Chair and the Commission, for allowing
us to participate today. Thank you.

My intent here is to kind of
provide the interstate pipeline's perspective on this
past winter, our experiences. It was, as you've
heard, a very challenging winter for -- for a lot of
folks, so -- I guess I'll -- I'll start off by, you
know, Transco is a very large -- I'll let the slide
catch up here.

Just a quick overview of the
Transco System. It's a very large and robust,
natural gas pipeline, with a lot of system storage,
almost -- a little over a hundred and ninety B.C.F.
of storage capacity, that -- that's located across
the system. The -- the blue boxes on the slide
indicate where that storage capacity and facilities
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are located on the system.

Just some highlights, from --

from -- from this past winter, January 7th seems like
a very popular day for peak days. It was Transco's
peak day, an all-time peak day with eleven point nine
million dekatherms delivered in our market area. And
we're defining the market area by -- Transco has --
has seven different rate zones and we're looking at
just Zones Four, Four-A, Five, and Six, so just that
part of our pipeline.

There -- there were -- there were
no interruptions and I'd like to really point that
out. No interruptions or constraints of primary firm
capacity, throughout the entire winter period. You
know, that's -- we hear a lot about -- about
constraints and curtailments, but really, when --
when the pipeline or the interstates are talking
about that, we're talking about curtailments or
constraints of non-primary capacity, secondary firm
transportation or interruptible transportation.

Deliveries for the period, and
we're looking at December of '13 through March of
'14, averaged one point four million dekatherms a day
greater, on average, than the same period last year,
which is a significant increase. And I think it'll illustrate that in a slide or two, coming up.

Twenty-four of our top twenty-five all-time delivery days occurred this winter. The only day higher was our peak day from 2013. We did issue -- the pipeline did imbalance operation of flow orders, really to protect system integrity.

And -- and just a little -- expanding a little bit on what the operational flow order actually does or at least, in our instances, essentially we're simply asking shippers, people moving capacity -- using capacity on our system, to -- to supply at least ninety-five percent of their delivery needs. So, there is still some flexibility, even when we have an operational flow -- flow order and it really doesn't impact capacity. It's just an imbalance management tool.

And then, non-ratable deliveries, I think that was touched on a little bit earlier. They provide challenges. Most of the production, the receipts coming into our system are all flowing on a ratable basis. Where the deliveries leaving our system, are -- you know, we have a similar peak to the electric generation. We have a morning peak, we
have an evening peak. So, managing those non-ratable deliveries are -- are challenging, but we do that through storage, management of line and other tools that we have. For -- for the Transco System, we don't have any -- any limitations on -- on ratability or how you can take the gas out of our system.

Okay. Here's the illustration about last year or the winter of 2012-2013 versus '13-14. About one point four million dekatherms a day increase, on average, for the four-month period. You know, it was very cold, obviously, but, you know, we -- we also heard that a lot of generators weren't even burning fuel during this period. So we still had a significant increase in -- in demand on our -- our system.

I -- I -- illustration of -- of our peak days, looking at the last several years, obviously, a steady increase year over year, primarily the result of expansions on our system. But you can see, a very significant increase between '12-13 and '13-14.

And -- and the orange line represents, actually, our contractual capacity on the system. So, you can see, almost in every year, our
deliveries exceed, by a large amount, this past year, our -- our contractual capacity. And that's accomplished mainly through segmentation of -- of capacity rights and -- and backhaul transportations where we used displacement to make additional deliveries.

Going forward, we're projecting and -- and I'll -- I'll look at a couple of slides on infrastructure changes that we are proposing and the market has received very well. You know, we're proposing or -- or -- or estimating our future capacity -- contractual capacity is going to grow significantly in the next three to four years.

A little bit -- a -- a look at where Transco is in relation to a lot of the major supply basins, we are very well positioned to take advantage of -- of really all of the shale -- shale plays in -- in the mid-continent, in Texas, obviously Marcellus and Utica. You know, traditionally, most of our production in the Transco System was off-shore Gulf Coast. That's still a major player, but -- but obviously not anywhere near where it was five years ago.

As I'll -- I'll illustrate coming
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up, Transco is in the process of -- of making change -- system changes to allow us to -- to reach back to this -- these supply basins, where, you know, traditionally, we moved gas from the south to the north. In 2015 and beyond, we are making significant changes to where we will be a bidirectional mainline system, where we can access Marcellus, Utica, any production in the northeast, and -- and provide transportation as far as south as -- as Alabama, for that gas.

Quickly, I'll take a look at some of the -- the infrastructure projects we are -- or have proposed. The first one is actually -- was placed into service, prior to this past winter. The Northeast Supply Link Project, it brought increased incremental capacity of two hundred and fifty million dekatherms a day, two hundred million of that into New York City -- capacity into New York City, placed into service last fall.

Northeast Connector and Rockaway, it's a one hundred million a day expansion from our Station 195, into, effectively, National Grid's territory in -- in New York City, with the -- the major piece of this being the Rockaway Lateral. It's
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a three-mile -- a little over three-mile lateral from our offshore connection. And it -- it will come on shore, on the Rockaways and provide, essentially, new gas service into National Grid's Brooklyn and Queens area.

And just for the -- for the record, we actually received FERC -- our certification from FERC on that project, this past Friday. So, we're full steam ahead on construction there.

Constitution, I'm sure it's probably been a very big topic for many, many different reasons. It is a proposed pipeline, interstate pipeline that's going to connect Marcellus gathering and provide six hundred and fifty million cubic -- or dekatherms a day of capacity, into Tennessee and Iroquois at the Iroquois Right Compressor Station.

Right now, we're looking at a target in-service date in late '15, early '16. We're still -- obvious -- obviously, going through the approval process on this project.

This is one of the projects I mentioned that is going to essentially make the Transco pipeline bidirectional, providing supply from
really any location along the way, specifically
the -- specifically Marcellus in this case, at five
hundred and twenty-five million a day of firm
capacity, with a contract path from our Zone Six, all
the way down to our Zone Four, but you'll have
delivery rights anywhere along that contract path.

And I think this may be the -- the
last project I -- I mention. Again, just recently
announced, but we do have market commitment for this
project, a very large project, one point seven
million dekatherms a day. Again, it's from the same
supply areas. This one's a little different, where
we have some new green-field construction that will
intersect with our mainline Near Station 195. But
essentially it has a path again, all the way back to
our Zone Four, but it -- it's also going to provide a
brand new market supply at our Station 195. And that
gas will have secondary rights, anywhere in our Zone
Six.

I'm not sure if that's the last one
or not. It is? Okay.

I -- I guess just a couple of
notes, just for the record. You know, we've
talked -- heard a lot about pricing today. The
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interstate pipelines, as I'm sure the Commission is well aware, we do not set the commodity price on -- on -- on pipelines, or on the -- the commodity delivered. We -- we're in the transportation business. We -- we are regulated on our -- our rates, so commodity pricing is something that we do not set.

Something that Wes touched on, we are very involved in Order 787, the communications between electric generators, operators, and -- and the transmission -- gas transmission providers, so -- and I think we've made a lot of progress there. We -- I think we have a long ways to go, but we are -- we're talking, which is probably the -- the first step, so I -- I think we're -- we're well on our way to -- to kind of closing some of those communication gaps that we've had in the past.

Thank you.

CHAIR ZIBELMAN: Thank you.

Ms. Bloodworth, welcome.

MS. BLOODWORTH: Well, thank you.

Chairman Zibelman and Commissioners, America's Natural Gas Alliance certainly appreciates the opportunity to speak from a producer perspective. We
agree with you. We do share the concern over the rapid price increases. Obviously not only for New York, but just the economy as a whole.

I very much appreciate your diligence and the Commission's diligence in this workshop and the inquiry. What we hope is it certainly will last, not just short term, but more long lasting solutions, but we definitely hope that one of those is focused on how we can get more infrastructure, to really take advantage of -- of the shale gas that is now available.

For those of you who may not be familiar with America's Natural Gas Alliance, we do represent the leading independent natural gas producers in North America. Collectively, our members represent one-third of all the natural gas production in the U.S., which is about eight T.C.F. per year, so an important group to the natural gas supply picture.

Our association is fairly unique. We're really focused on state, federal and regional policies, but we're more focused on the market. And by that, I mean our overall goal is to increase the demand for natural gas.
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I never can make a presentation without showing the shale -- kind of the shale map. These are all the shale plays in the U.S. The reason why this map is important, because these shale plays, every time I show this map, we're adding a new one because of the economic opportunity or the potential for that basin to be developed. Natural gas is now produced in thirty-two states.

But I think what is important from this slide is when I think about the emergence of the Marcellus and all of the shale basins. I've been in the natural gas industry for almost twenty-five years. The shale gas revolution has virtually happened in the blink of an eye. And so, as we all try to adapt to this prolific resource and the economic and environmental opportunity that it presents, it certainly, even as I look at my role, which is more focused on power generation, our industries certainly are now working together more collectively to really understand both the challenges and the opportunities.

And I think the polar vortex, I really want to, you know, give a hats off to New York ISO and many of the I.S.O.s that we work with
throughout the country, because the natural gas industry and the electric industry, from a communications perspective, really did make great strides. And I think that's why you didn't see any blackouts. And those that subscribed for firm capacity received that firm capacity.

But we're still learning. And I think that, you know, it's sometimes hard to recognize just how quickly this paradigm revolution has occurred.

As it relates, when we think about the shale gas industry, just very quickly, certainly it is a huge economic driver. By 2035, the shale gas industry will represent four hundred and seventy-five billion dollars to this nation's economy. It will have created three point five million jobs. Something important for all of us.

But the last takeaway on this slide is if there's any uncertainty about the supply and the size of this resource, if anything, it is on the upside. And I'm going to share with you in a minute, as we look at just a twenty-four percent increase by the potential gas committee and the size of the resource, but just in two years because the
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technology that the members that I represent are deploying, it is getting better and better, meaning they're able to more and more gas, more efficiently.

The good news is you look at the northeast and where you are situated, when we look at, you know, where kind of the largest emerging shale plays, obviously, certainly the Marcellus and the Utica. With the Utica only being in its infancy, we have yet to develop the full potential of the Utica.

But half of the natural gas production is going to come from this region. So, you're certainly well situated and close, at least, to the supply basins. We know we have to get some more pipeline infrastructure.

And one of the reasons why Richard talked about your seeing movement of the northeast gas to the southeast, because as we look at the production potential, there is not enough demand in the northeast. So, by 2017, you're going to see, eighty percent of the time, supply from the northeast, beginning to go to the south and other markets who don't have, maybe, access to such robust supply or -- or basically, because the demand in the
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south is growing at such a fast pace.

We recently did a study with Bentek, which is one of the leading energy analysis in the U.S., just really looking at what is it going to take to see high-case scenario of production in the northeast. As you look at this slide, right now in the Marcellus, there are about seventy-five rigs. But the rig count -- now, we don't use rig count to measure how much production. And that is because of -- we're able to drill wells two to three times more quickly.

We're able to bring gas more quickly, to the market. Many of our members, where it took them thirty days to complete a well, now it may take them only two days. The horizontal laterals, their ability to extend underneath the ground, is getting longer and longer, which means more and more gas.

So, when I ask my producers what keeps them up at night, it's having more of a demand market is what they worry about. It's not enough demand to keep that healthy supply growing and -- and moving forward.

We are seeing, as Richard
mentioned, though, a lot of new infrastructure being invested. Because if you're a producer and you have billions of dollars in the ground, that's an asset you want to make sure that you can move to market, so a big change is more producer push pipelines, where they're trying to build pipelines to get them to the liquid trading points. Next slide.

So, Richard touched upon many of those. Certainly, when we look at the northeast, the natural gas industry is really striving to move forward with these infrastructure projects to meet the growing demand. There is substantial growth in natural gas supplies within the Marcellus basin, on the board of the northeast region, both New York, New Jersey, and New England. But even so, there certainly is the need for further infrastructure investments.

And the big question is how do we pay for that. I don't really think there's a one-size-fits-all solution. I think it's going to be a combination of both state and federal rules, within the I.S.O. R.T.O., creative mechanisms, that maybe are looked at from a state perspective.

There's a lot of proposals, I'm
sure you guys are aware, from a New England pay-for-performance, to a NESCO governor's proposal, all designed to try to take advantage of this masses -- massive resource and get it to market. But when you look at expansion, overall, capital that's been made in the U.S., the good news is between '013 to 2015, fifty-seven percent of all the investment in pipelines, is going to occur in the northeast. In the next three years, these are all of the projects. Some of those are backed by L.D.C.s, some of those are what I mentioned, more of our members, the Williams Constitution is two of our members, Cabot and Southwestern Energy, are really investing in that pipeline, because they do want to bring natural gas to the State of New York. We call that more of a producer push pipeline. The Spectra, New Jersey/New York, pipeline is really a supply push and a market pull, where you have a combination of producers investing in part of the pipeline and then you have customers like Con Ed, who are really pulling that demand, who are making the other investment, to justify the economics to make it move forward.
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There certainly are constraints, though, in the northeast -- I mean, the eastern part of New York and New Jersey, which is really why you saw these huge price spikes and why you didn't see them in Birmingham, Alabama, is because in the southeast region, we do have a significant amount of firm transportation and storage, certainly a different regulatory mechanism.

I'm not advocating for regulating. I think either market can work, either way, organized or regulated, if the right rules are in place.

I think we've already all agreed that it certainly was a cold winter. And so, as we look at market solutions moving forward, I do think, though, we need to recognize, at least, the good news, that when we looked at the overall requirements for natural gas demand, supply certainly was there.

Just looking at it from a pure natural gas perspective in the U.S., you can see that the winter's peak demand, as we look at what was the average peak demand over the United States, for natural gas, over the past five years, we basically had to produce or deliver twenty-one -- twenty-one B.C.F. per day. It was an eighteen percent increase
over the five-year average. We did exceed the
highest demand seen in the last ten years, by fifteen
B.C.F. per day, or twelve percent. And in all, six
days exceeded the highest level in the past ten
years. But again, showing you, the supply certainly
was able to get to the market.

I'm going to skip this slide, just
because I think we've talked enough about how cold
the weather was. I think we pretty much all
recognize that.

All right. So, we -- as we look at
prices, really from different regions, looking at
these liquid trading points and how prices, because
of down-stream constraints, really were elevated,
mostly, as you look at this chart, the blue line,
which you really can't see, which is Henry Hub,
really didn't see a lot of price volatility like we
did at some of the -- the New York more trading
points, Algonquin and also Transco Zone Six. But you
look at -- even though the northeast, we typically
always see price spikes.

Obviously, with supply and demand,
the market is going to send that signal. And when
supply -- when demand goes up, prices are always
going to go up. But the reason we really saw the extreme prices, the hundred and twenty dollars, the hundred dollars, is not because there is not supply, but basically, we couldn't move that gas to get it to the load centers where it was needed, because we didn't have the adequate infrastructure. And that's when you're going to see the huge price spike.

Lots of discussion about basis blowout. I think it's important to look at there was not a basis blowout as -- as you look at Pennsylvania. But as far north as Pennsylvania, when you look at Dominion South, which is a major indicator of prices in that region, it was very interesting that on the same day, when the New York price went to a hundred and twenty dollars, the going price in western Pennsylvania, was only four dollars and thirty cents.

Also, at Tennessee Gas Pipeline, Zone Four, on the same day, receipts actually were below the Henry Hub. I had members who were trying to give away their natural gas because there was so much of it and it was only at three dollars. And again, that is so contingent upon having the adequate pipeline infrastructure in place, which certainly
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will get rid of a lot of that volatility that we're seeing.

Producers, I think it's also important to recognize that they're hurt by pipeline constraints. And that's why you're seeing a lot of producers really doing these push pipelines, because once that well starts flowing, the reason why they have to buy storage is because they're not going to shut in that well, and it is a very ratable flow. And so, as demand changes, many of our producers do have storage assets, really to manage that imbalance, just like an end user customer would have.

So, what are the takeaways from this winter? Supply increases are more than keeping up with demand. Obviously, not where pipeline constraints restrict the flow of gas to customers. Customers with firm supplies, it's just like an insurance. They certainly paid more, but they didn't go without gas and even on the coldest days of a very cold winter.

Power producers in the northeast did rely on alternate fuels to make it through. But wholesale electric -- electricity prices reflected the scarcity of gas supply and the high price for
fuel oil in eastern New York and New England. So, until we find a way to free up capacity for power generators during those peak times, the situation will only get worse in the coming years.

Again, we feel like it's really going to take a portfolio of options. We are finding that customers who purchase their gas on a monthly basis, not totally dependent on spot pricing gas, obviously fared much better. They may have paid a premium overall, but again, did not see the volatility that some customers did, who were buying gas on the daily market.

So, I -- as we look at just the pipelines that are permitted or in the permitting process here in the State of New York, we certainly would encourage the state agencies to work as quickly as possible, without sacrificing the review of those projects, so we can move much of that gas supply to the State of New York.

Thank you.

CHAIR ZIBELMAN: Thank you.

Mr. Rooney, welcome.

MR. ROONEY: Madam Chair, Members of the Commission, good afternoon.
Since it's me, then lunch, I will try to be concise.

By way of background, the petroleum industry supplies almost six billion gallons of petroleum products annually to the downstate region, about half of which is motor gasoline, while the remainder is a variety of distillate products and jet fuel.

Over the past five years, total distillate consumption in this region has been on the order of a little less than three billion gallons a year. So, on any given day, in January, more than about twenty million gallons of gasoline and other petroleum products are moving through the multi-faceted and highly complex network that makes up the petroleum supply and distribution system, in the downstate region.

Consumption by sector shows that residential consumption is by far the largest amount, with commercial, and that includes apartment buildings in New York City, and on-road diesel, about the same.

For a variety of reasons, the industry supplies petroleum products on an as-needed basis, which we refer to as just-in-time inventory.
What this means is that there are physical supplies available, in the distribution chain, equal to about four to five days of normal demand.

Over the past two decades, the nature of the wholesale and terminal operation segment of our industry has drastically changed, due to -- one, is a -- a twenty to twenty-five percent reduction in both commercial and residential heating oil usage, primarily as a result of aggressive conservation measures. Secondly, the escalating cost of environmental compliance. Third, increased general business and operational costs. And lastly, the role of the commodities futures market and the pricing of petroleum products and the potentially negative impact, which it can have on the value of physical product storage.

As a result, there are far less storage terminals and petroleum storage capacity than just a decade ago. Thus, the industry's ability to meet sizable incremental demands from the electric and interruptible sectors, is clearly constrained during winter periods of high demand.

The -- the draft State Energy Plan, clearly recognizes the important role which the
industry plays in ensuring electric reliability, noting these distillate fuels are also used by the electric sector for primary electric generation and as crucial alternative back-up fuels, helping to maintain electric reliability, particularly in the downstate region.

Over the past two decades distillate storage capacity has declined by some one hundred and thirty million gallons, or thirteen point one percent, while demand has only declined by about five point eight percent. The draft Energy Plan recognizes the potentially dire consequences of this imbalance, noting that there may be less capacity available, to meet atypical demand surges by the heating and electric generating sectors, during periods of colder than normal temperatures. In effect, consumers are becoming more dependent on the ability of the petroleum transport industry to resupply the remaining terminals, during periods of peak demand.

As noted earlier, my industry is structured to deliver about ten million gallons of distillate products a day, in January, which is traditionally the highest heating volume demand month.
of the year. This past January, what a doozey that was, we experienced significantly colder than normal weather and thus demand from the commercial and commercial-residential, and suburban-residential sectors, increase by some thirteen percent, or about nine hundred thousand gallons a day.

In addition to the increased demand from our oil heating customers, there was also a cumulative total of thirteen full days of gas supply curtailments, one of which lasted for a full nine days, to large volume entities such as electric generators, government facilities, universities, schools, hospitals, and commercial establishment, which purchased gas on an interruptible basis.

From data supplied to us by D.P.S. Staff, there are four thousand six hundred and ninety-nine sales and temperature controlled interruptible customers. That is ninety-five percent of the statewide total, located in the downstate region.

Again, according to D.P.S., a full sales and temperature controlled gas interruption displaces about two hundred and sixty-seven thousand dekatherms, which is the B.T.U. equivalent of almost
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two million gallons of heating oil a day.

So, an industry configured to supply some ten million gallons of distillate products on a normal winter day was now facing an increased demand from its own customers and from curtailed natural gas customers, of close to thirty percent, or an additional three million gallons a day. Significantly higher than normal demand and severely constrained supplies, will, of course, be reflected in the most obvious economic variable. And that is price.

According to NYSERDA, the average residential heating price in the downstate region increased by some thirty cents a gallon, from January 1 through the first week of February. The retail price reflects the twenty-nine-cent-per-gallon increase, in the January U.L.S.D. settlement price on the New York Mercantile Exchange, which, in turn, is reflected in higher wholesale prices at fuel terminals throughout the region.

MR. ROONEY: It should also be noted that the price of ultra-low sulfur on-road diesel also increased by some nineteen cents, on average, during the same period, due, in large part,
to increased demand for ultra-low sulfur heating oil
since, in New York, they are now essentially the same
product.

So, for a variety of reasons, the petroleum industry in New York, continues to
donsize. There is less refinery output, less
available bulk storage capacity, and less demand from
traditional sources.

By the same token, demand for
natural gas supplies, from electric generators,
interruptible and firm gas customers continues to
increase. However, those gas supplies continue to be
constrained during periods of extreme or abnormally
cold weather conditions.

Warmer than normal weather
conditions, over the past few years, have simply
papered over the problems, which the entire energy
industry experienced this January. Ironically, while
the natural gas industry is -- is aggressively
seeking to add more firm load to its systems, at the
expense of the oil heating industry, it is becoming
more dependent than ever on that very same industry,
in order to maintain gas supplies to its firm
customers, during cold weather periods.
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Only the relief valve, of its interruptible gas load allows the gas industry to meet its peak firm load, as happens -- as happened this winter. The ramifications of this flawed strategy are self-evident. As more firm gas load is added, the likelihood of a greater number of gas interruptions, for longer periods of time, increases exponentially. At the same time, the ability of the petroleum industry to meet an unanticipated twenty to thirty percent increase in daily demand has decreased exponentially.

The gas industry clearly benefits from being able to curtail interruptible customers to meet peak demand from their firm customers. By the same token, electric generators, municipalities, and large commercial industrial entities, also benefit from the substantial costs savings of being able to purchase gas on an interruptible bases. As such, they need to be proactive in order to fully and properly prepare for the increased likelihood of interruption events.

These large volume customers need to be told, in no uncertain terms, that if they wish to continue to derive the financial benefits of
buying gas on this basis, then they have to make the necessary financial investment to install adequate supplies of their alter -- alternative fuel, physically on site for those times when their gas supplies are interrupted. In all honesty, this is just common sense.

Attached to our formal statement are recommendations which are summarized here on alternative fuel supply, which we respectfully urge the Commission, the electric and gas utilities, and their customers to consider. Because the ultimate mistake for them would be to do nothing and simply assume that the oil industry, as it is currently configured, will always be around to support a gas supply demand imbalance, which they, themselves, have created as a fundamental part of their operating systems.

In the competitive energy markets, heating oil is usually viewed only as a competitor. The reality is not as distinct. Our industry acts as a critical back-up fuel supplier to both electric generating and natural gas customers, enabling facilities that are essential to the state energy sector and the state's energy consumers to keep
operating. It is important to recognize the interconnected nature of the relationships which exist between all fuels, in order that the reliability of supply and the price-ability of all fuels are achieved.

In conclusion, for the regulated gas and electric utilities, when both electric reliability and fuel supplies to schools, hospitals, apartment buildings, and commercial establishments hang in the balance, gambling on my industry's continued ability to supply them and their customers during periods of extreme cold and high demand may well prove for them, to be little more than a Hobson's choice. That is taking what we can realistically supply, or nothing at all.

Thank you for your time.

CHAIR ZIBELMAN: Thank you.

While I understand everyone's been sitting here, I think these issues are too important. And rather than bring the panel back, let's -- if you don't mind, let's take a few minutes and I want to make sure we all have had a chance to ask our questions.

So, just to -- just to -- I want to
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go back to a point, Wes, that you made at the end, which is that there is a significant value about being part of an eastern interconnect, where you have large markets and you have the ability to import, export, to take care of price differential. And I -- I don't, obviously, disagree with that. I think it's of huge value.

My only point was a small point and I would ask that the ISO look at it. If in fact, we see, somehow, an emerging issue that exporting influences one part of the price in the -- in the New York ISO, I think that that is become -- load, itself, becomes part of a storage, essentially, or it should be effecting -- that they're being adversely effected would be is if one generator was adversely effected that would otherwise be economically dispatched, but would -- is somehow constrained. And I think this just merits looking at what is influencing this price differential, so we know that if we're looking for a solution, we're -- we're focused in the -- in the right direction.

Not -- not to disagree, though. We don't want to stop importing and exporting because it helps us.
On terms of this -- there a couple of issues. Cortney you raised an issue and I -- I just want to make sure I understand it. I mean, basically what you're saying is that in order for any generator -- a gas generator to maintain adequate fuel supply, whether it's -- and I'm going to ask you this, I guess, more of a question, whether it's firm gas or back-up resources in inventory, your suggestion is -- is that that -- that imposes a cost and that maybe there should be an additional product that values that in the market? Is that what you're suggesting?

MS. MADEA: Yeah. I was just talking about the oil resources and in terms of their inventory, in -- so this -- this notion where generators should be somehow incented to -- to keep that oil inventory high. That's what we're talking about, about establishing a separate New York ISO product, where it would compensate it as a -- as an ancillary service.

CHAIR ZIBELMAN: And --

MS. MADEA: And I think --.

CHAIR ZIBELMAN: -- would that be a product -- I mean just in order to be somewhat
neutral in terms of technology, wouldn't that be a product that you would say is a -- an alternative to relying on natural gas, so if it's storage, or if it's wind, or if it's solar, or if it's nuclear, if it's hydro, they're providing the same benefit? Is that correct?

MS. MADEA: Yeah. I think -- I think that could all be fine and we'll get to the same issue. And I think where that -- where that comes from is -- you know, Michelle mentioned the New England PI proposal and there is talk in the New York I.S.O. of somehow penalizing oil generators, one month's capacity payments, if they're not available. And I think both of those -- the -- both of those things are policy changes that would discourage the older oil units, which are the units that kept the lights on this winter, from participating in the market.

And so, what we're -- all we're saying is that we need policies that go the other way. Instead of putting more risk on them and punishing them, ones that recognized the importance of them and keep them around.

CHAIR ZIBELMAN: Provide incentive.
And that -- I mean, I was thinking that -- that demand reductions, type of things that Mr. Mager was talking about would fall into that, too.

MS. MADEA: Uh-huh.

CHAIR ZIBELMAN: That they have a benefit.

Okay. And then, Mr. Truxell, I -- and I -- and I need to understand because listening to both you and Ms. Bloodworth, I mean, I -- what I'm hearing and I think everyone else has said, this is not a -- it's not a supply issue. There's plenty of adequacy of gas supply and we see some of the basis differential, in that there is probably people who want to provide gas that just couldn't get it delivered to the points.

But you -- and -- and -- and you indicated -- you said well as a pipeline, your prices are -- are regulated, right, on -- at least on the firm pipeline capacity?

MR. TRUXWELL: That's correct.

CHAIR ZIBELMAN: But on the non-firm capacity, on that piece of it, there is a second -- I mean, as what I understand, is that --
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that's the part of the capacity, as it gets released, is influenced by demand and that's where we saw the price rises; right?

MR. TRUXWELL: It -- that is correct. In the secondary market, there are -- those prices are -- again, are still not set by the pipeline. They are still -- they're set by the market. We just have a mechanism to allow our shippers to release their capacity to a third party.

CHAIR ZIBELMAN: Okay. And -- and so, if -- if I were -- if I'm just following the money the correct way is -- is that then -- from the perspective, is the producers weren't making more -- necessarily more money. It's just the folks that -- what we call a gray market, the secondary market, where we saw that the ability to profit from the scarcity -- or the -- the high demand, I would say?

MR. TRUXWELL: Yeah. I would -- I would say that is correct. I don't have, you know, the evidence of -- of that, but I -- that is essentially how it works, though.

CHAIR ZIBELMAN: And -- and is that -- so, then my question had been to you, Ms. Madea, does energy by firm pipeline capacity -- and I
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would say, Mr. Parisi, you too, is that -- I mean, this -- this becomes, I think, the -- the horns of the dilemma. Who will -- I mean, we have, on one side, Ms. Bloodworth is saying that some of the producers are starting to push for increasing pipeline capacity, but are -- are you -- are you folks seeing a need to maybe think about this as a value of making certain that you can hedge or protect yourselves of looking at buying additional firm pipeline capacity, to ensure reliability of the -- of the resources and their availability when we need them?

MR. PARISI: I -- I would have to find out for sure. I believe -- I believe we do some, but not completely.

MS. MADEA: Yeah. And we have some, as well. And then in constrained pipeline areas, we have firm from third party suppliers. And so, I think the -- basically, the -- from talking to our gas guys, it's we have the firm that we need in the constrained areas, but this notion of requiring it all across the board, that's just a -- a second step that doesn't seem necessary at this point.

CHAIR ZIBELMAN: Not necessary from
the standpoint of required to make your -- keep your
units running?

MS. MADEA: Yes.

CHAIR ZIBELMAN: And -- and -- I
mean, I -- and I -- the obvious point, obviously, if
you're buying firm and others aren't, there's a
potential cost that you're incurring that doesn't --
 isn't necessary, as -- as long as gas is hitting the
marginal price.

That -- and so it follows -- so
that -- and then that becomes the horns of the
dilemma, who in the industry -- and it might be the
producers, but who else -- and that's our -- is going
to buy it, because obviously if there's no demand, no
one's going to -- you're not going to be able to
build. Is that -- following all this correctly;
right?

I'm not trying to cross examine. I
mean, I think that our -- the biggest dilemma I have
is who, anymore, in this -- in our restructured
industry --

MS. MADEA: Uh-huh.

CHAIR ZIBELMAN: -- is the natural
entity to create the demand for firm pipeline
MR. TRUXWELL: Okay. And -- and many of the -- many of the projects that we -- that I mentioned today are, as Michelle mentioned as well, are -- it's the producers that are -- are signing up for the firm capacity because they want to get their product to market.

MS. BLOODWORTH: But let me just clarify. All -- all of our producers have different business models. So they're going to look at their investment and their return, as well.

New York, you know, from a producer push pipeline investment, we -- we are seeing more because they feel like the economics are justifying, based on the demand, different than, you know, building pipelines to New England. However, I would caution that.

And again, each one of them looks at their business model differently. They're going to invest where there's a lot of regulatory certainty and where they also think, whether you're N.R.G. or Con Ed, that they have the market incentives and the mechanisms to be able to contract and recover those costs for that service.
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But the producer push pipelines, they're still only investing to these local trading points. And so, where they're not able to extend is that last -- that last mile. And so, in order to get it to the load-serving entity, the generators really have to have the incentives that value reliability. And -- and I'm very much with Cortney, that, you know, you shouldn't be mandating, you know, one fuel option over another. Let the market work. Let -- let the fuel options compete. But again, we just have to make sure that those market rules are incentivizing and valuing reliability enough to let that market work, if that makes sense.

CHAIR ZIBELMAN: And -- and in terms of that, I mean, from your perspective, Cortney, is one of the issues around the ability to sell forward, on a firm basis, versus a -- I -- I'm just thinking if -- if you had -- if we had more longer-term hedging in the market on the demand side, would that help -- in your view, help provide the right incentive, so that the desirability of having more firm capacity on the delivery side would drive that? Would be one of the natural market incentives?
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MS. MADEA: Yeah, maybe. But I guess right now, where we are is that there's enough liquidity, enough availability in the spot market for us to get what we need to run our plants. And so we don't see -- we don't see firm gas as our -- our issue or the solution to any problems that we're having.

And I think, in one instance, we even had one of our plants that has firm, it got cut. So, it doesn't get us where we need all the time.

CHAIR ZIBELMAN: Okay. Thank you.

Any questions?

COMMISSIONER BROWN: Just one quick question for anybody that happens to know. Did any generator require any D.E.C. permit, waivers for your resources because they couldn't get the proper fuel that they needed this winter?

MR. PARISI: I -- I knew one of the plants was -- was attempting to get that. I think eventually they got their fuel supply straightened out and didn't need it, but there was a barge --.

COMMISSIONER BROWN: So, they --

they were trying --

MR. PARISI: They were trying.
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COMMISSIONER BROWN: -- but ended up in the end --

MR. PARISI: That's right.

COMMISSIONER BROWN: -- Charlie's guys --

MR. PARISI: Yeah.

COMMISSIONER BROWN: -- came through?

MR. PARISI: Yeah.

COMMISSIONER BROWN: Okay.

MR. ROONEY: We -- we -- actually, our industry sought a -- a waiver of the ultra-low sulfur requirements.

CHAIR ZIBELMAN: Any further questions?

Okay. Well, we'll break for lunch and thank you very much.

(A luncheon recess was taken at 12:52 p.m.)

(The hearing resumed at 1:48 p.m.)

CHAIR ZIBELMAN: Commissioner Brown observed that one thing as sort of our takeaway from today, is it was really cold this winter, in case anyone didn't notice.
So, thank you, and we're going to go on to the -- the new panel. I guess that joke just sort of fell flat. In the interest of time, we'll -- we want to make sure to try to get folks out of here, as close as we can to five o'clock.

I've lost my sheet.

Okay. So this is Panel Three. And today -- you know, we had the suppliers and now, essentially we're talking to the purchasers and really kind of getting an understanding of what -- what's happening on the demand side of the equation.

And with that, our speakers today are Patrick Badgley, who's the Associate Editor of American -- American Natural Gas, from Platts. King Look, who is the Director of Electric Supply with Con Edison, of New York. William Atz1, who is Director of Rate Engineering, with Con Edison in New York. Christopher Wentlent, who's with the New York Retail Electric Supply Association. Margaret Janzen and Pamela Dise, Margaret is the Director of Wholesale Supply with National Grid and Pamela is the Director of New York Pricing for National Grid.

So, welcome to the panelists. And as I said, I'm very, very interested in this whole
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issue of how do we create hedge products, if that's -- if that's a solution. And I know you've all prepared remarks, but certainly it will be helpful to me to get a picture of what kind of products are out there offered and what -- what better things we could be doing.

I know that the utilities already hedge on -- on pieces of it. It'd be helpful to understand what they're doing.

And then, Chris, it would also very helpful to understand from the ESCO perspective, what can -- what's being done and what -- maybe what things we could do, or help out and get done better.

So, with that, we'll start with Patrick. Thank you.

MR. BADGLEY: Thank you, Madam Chair, and thank you Commissioners, for having me today.

I'll start out just by kind of giving an -- an overview of Platts and what we do and how -- you know, the -- the role that we play in these markets. And -- so and our first slide here, just to run down, we've got ninety-nine pricing points in the daily spot market and that's including
locations in the U.S. and Canada. In addition to that, we actively track markets to see where new locations should be added, which is a -- a really key issue.

Right now, with the -- with the onslaught of all this Marcellus production and -- and in fact, the most -- the most recent point, which came just about a month and a half ago, is related to that. It was the Tennessee Zone Six, three hundred leg point, where there was a bifurcation in the market between production and the Tennessee Six, delivered. So, you know, that's an indication of how these markets are changing and -- and the different kinds of production we're seeing.

So, what we accept in our -- in the -- the trades that were reported to us, are negotiated fixed price trades for -- in the spot market -- in the daily spot market, for next day delivery. We receive transactions from the back office of companies, from risk departments and not the traders, themselves. They are given to us electronically and we -- we have records of those. We have clearly defined price points that are outlined in our methodology. And our
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independent editorial process requires us to go through those sheets, review the prices and, you know, in cases where it's necessary, make sure that they're mapped correctly and that we're speaking with the companies to understand -- to make sure that there's the correct understanding at all levels of where this price is going and where it -- what pricing definition it belongs in.

And in our monthly markets, we have trades from the -- this is referred to as bidweek, the last five days -- the last five business days of the month. Larger amounts of data there, same price analysis process, and basically that -- that covers physical basin -- or I'm sorry -- the base-load gas for next month delivery. In that you also see the low and high range deals, index volume and deal counts published for each of the locations.

So, when we refer to -- to basis at those points that are -- that are east of the Rockies, we're talking about the basis to the NYMEX Henry Hub contract. And basically the forward -- the forward basis references that market as a differential to the Henry Hub. You know, clearly at -- at congested points in the northeast, you can
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see very high -- very high, positive differentials.

Other points, you might see lower differentials.

The NYMEX covers the following
month of the year, which is very -- very closely
watched by the market and also allows hedging for
months in current year, in addition to the next
twelve calendar years.

Then you have an intercontinental
exchange, which is a major trading vehicle for spot
market trading. There's also forward availability on
that.

This is a recent screen shot, about
a -- a week or so old. You have this year in
January, we were seeing prices up in that triple
digits in some cases, forty, fifty dollars. So,
things have certainly settled down since then, but,
you know, at a very high level of volatility. You
know, so the question there is how did these prices
go from four to five dollars at the well head, with,
you know, a -- a dollar for -- for transmission
capacity, to a hundred dollars -- a hundred and
twenty dollars at the New York Citygates. And the --
the simple answer is that the congestion on the
pipelines, heading into that region.
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You know, this year, day after day, we saw operational flow orders, which were discussed before and, you know, made shipments match up with -- with what was scheduled.

In addition, you have the -- the shippers who own firm capacity and who own the commodity. You know, basically, the prices at the -- at the Citygates really represent a bundled price between those -- between those two costs. You know, so what people are willing to pay at the Citygate is the price that you'll see. And, you know, that's, in essence, a bundled package.

Now, in that kind of congested environment, those prices can really -- can really rise as power generators can face penalties, if they're scheduled to -- to dispatch, but can't run, or if obligations aren't being met, there can be penalties. The environment also led participants in the market to urge ICE to increase the maximum spot physical offer to a hundred and ninety-nine dollars, up from ninety-nine dollars. And that -- that came during some of the harshest periods of the winter. And you certainly saw it reach above the previous ninety-nine-dollar price level, pretty quickly.
As we've heard today, the fixed capacity is more expensive. And power plants that are fueled by gas, you know, say they don't necessarily need the gas to be flowing all the time. So there is certainly an understanding of why they might not subscribe to firm capacity, especially at gas-peaking plants. So, there are some capacity markets, address those -- address that higher -- higher cost firm price.

So, you saw prices, as I mentioned, really reach above the ninety-nine-dollar level, pretty quickly, after -- after the change on ICE. And this is just kind of a quick look of -- of some of the highlights that we saw this -- this winter, as far as -- as far as the high prices.

You know, fairly early on, over the -- the Thanksgiving weekend, you know, we saw Winter Storm Boreas, which drove New England prices up to about ten dollars. And, you know, that was -- it seems kind of tame in retro -- in retrospect, considering what we saw this winter, but, you know, after -- after a couple of years of -- of fairly low volatility, it really -- really stuck out and kind of was a precursor to what was coming on this winter.
On December 6th, we saw western prices hit multi-year highs as -- as we saw a winter storm -- another winter storm pretty early in the year. January 3rd, we saw ten-year highs in the Midwest, Chicago Citygates and Michigan Consolidated. January 21st, Northeast prices hit all-time highs, with a -- a hundred and twenty dollar prices at Transco New York and Transco non-New York. And then in January 27th, we saw another round of -- of high prices.

And not to be left out, in -- in February, the western -- Western U.S. really got a -- a dose of nasty weather and prices there set records at about forty-three dollars in the spot market.

So, at -- at some points, it really felt like the winter that wouldn't end. And New York prices really weren't -- weren't alone in -- in experiencing those extremely high levels, but -- but certainly -- certainly, were the exception in -- in how high they did go.

So, you know, kind of trying to -- trying to reconcile that with -- with the amounts of -- of production that is just really greatly growing in the United States, all the headlines
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you've seen have been regarding the -- the shale market -- or the shale production and just how much that's kind of a game changer.

But, you know, Bentek, which is a -- a Platts -- the Platts analytical unit, is forecasting production will average around sixty-eight B.C.F. per day this year. And that's about two B.C.F. higher than -- than last year -- two B.C.F. per day, higher than last year.

And you're really seeing evidence of that already, now that the winter has come and gone and some of the -- the freeze-offs that we saw at the wells have been -- have been shaken off. Northeast production, in the last week or so, has averaged more than fifteen B.C.F. per day, which is -- is quite amazing. It's thirty percent above the same period last year.

But even with all that, you still have the constraints heading into the eastern consuming markets and the trouble getting to that so-called final mile in the -- in the key market centers. So, as -- as has been mentioned it here today, there's the more producer -- you're saying more producer pushed product -- or projects on the
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pipelines, than consumer pull products and it's really -- really challenging to get -- to get -- to get the pipeline in that last -- the last stretch where the demand might be that heaviest.

So, somewhat counterintuitively, despite all that -- that production that's coming on in the Eastern U.S., you're really seeing Eastern U.S. consuming regions, they came into this season with a -- with a -- the five-year low for their -- for their storage inventories, so that, you know, they had -- they started low. You know, in speaking with -- with market sources, there was a feeling that -- that Marcellus production would kind of make up for the -- the inventory.

And as you see, we also came out of the season at a -- at a five-year low. And next year, expected with storage inventories, even lower than last year. So, that is a concern. It's a big project in building up these -- in building up the storage inventory.

So, in the U.S. overall, there was a -- a -- a -- the storage withdrawal season came out at the lowest in eleven years. Season kicked off -- this injection season kicked off with a couple of
lower than inspected injections, but those are -- are picking up now. And because of that, the NYMEX, in the last -- the last week or so, in -- in light of these -- in light of these recent storage and heavy storage injections, has really gone down in price. And you can see the -- the heating degree days there were far above average in -- in a couple of months this year. So, there was a -- it's very clear what -- what was happening.

And I'm sorry, I'm running out, but if I could just have one minute --

CHAIR ZIBELMAN: Go ahead.

MR. BADGLEY: -- to run through?

Okay.

So, we've also noted that -- today, that coal and -- and oil fired generation were relied upon much -- much more this year, as compared to the last couple of years because of -- because -- and -- and it was economical because of -- of constraints.

So, you know, it will be interesting to watch that going forward as new regulations come into place that, you know, in natural gas, is at this point, the preferred fossil fuel and the -- as it's evidenced in the new builds that we're seeing.
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The next chart here, we just give you a quick look at -- the orange line is the -- the Transco New -- Zone Six New York price. And it -- it was well above comparable fuels for -- for a good chunk -- or for several occasions on this winter.

Now, because of that, we also are coming in with a pretty -- pretty low stockpile of coal inventories, nationwide in the U.S. and, you know, that really could lead to more natural gas fired generation this summer, you know, even with prices being -- being at levels above where they were last year.

And just a -- a couple more slides here, with just a couple -- a quick look at -- at prices. You know, it's -- it's no secret that we've really seen things go quite up a bit, but I think this illustrates, you know, the -- the New York and -- and the Eastern U.S. were really quite exceptional in what -- in how high prices went.

And in the production regions, along the Gulf and at Tennessee Zone Four, three hundred leg in the Marcellus, you know, which had -- had -- and not too long ago, in -- let's see, October, had spent some time at about twenty-five
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cents, kicked back up to about -- about four dollars and fifty cents. So, obviously not the -- not the basis blowouts there, but some -- some significant increases.

And then looking ahead in our -- in our forwards packages, you can see that it's a -- it's really quite a different story. In 2014, which is represented by the -- by the blue bars, you see that Transco New York is -- has actually gone pretty far negative to Henry Hub basis. And again, that's the onslaught of the Marcellus production.

In Algonquin, even in that congested market, there's a pretty significant drop in -- in basis there. And in Dominion South, the production region, it's -- it's a -- a similar story, to even a greater degree.

And then for the coming winter, though, it is -- it is pretty clear, our forwards are showing that there were -- were some -- that basically, this winter got into the psychology of people involved in the market. If you look at Algonquin, it's up to about plus eight dollars and twenty-five cents for the -- for 2014 winter, which covers November through March and that's more than
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double 2013 and Transco New York also -- also comes up very high there.

CHAIR ZIBELMAN: Thank you.

MR. BADGLEY: Thank you.

CHAIR ZIBELMAN: Mr. Look, we'll turn it over to you.

MR. LOOK: Thank you.

CHAIR ZIBELMAN: And by the way, I didn't mean to scare anyone. We're -- we're still going to try to end at four o'clock. I think I had said five.

MR. LOOK: Okay. Okay. Thank you, Madam Chair and Commissioner.

Con Edison will welcome the opportunity here to -- to provide a -- an overview of our hedging program.

First slide. The next one. Yes.

Yes.

I'll be speaking, provide an overview of the hedging program. My colleague here, Mr. Atzl will provide a discussion on the supply cost recovery mechanism.

Yes. A hedge is a -- is an investment made to reduce the -- to reduce the
significant price movement in an asset. It generally
does this fixing or limiting the price movement.

Con Edison's hedging program is
designed to mitigate price volatility of customers.
The goals of the program are fundamentally based on
Commission order, in case zero six dash M dash ten
seventeen, which states electric utilities have been
expected to manage the electric supply portfolio, in
conformance with the principle established in the
retail market policy statement, where it was
determined that electric utilities should maintain
balance commodities supply portfolio characterized at
neither zero percent, nor a hundred percent hedge,
for serving residential and small commercial and
industrial, collectively, mass market customers,
unquote.

Electric -- electricity price
volatility is primarily caused by changes in the cost
of the underlying fuels, used to generate
electricity. A shift in the supply and demand, due
to weather and/or unexpected loss of generation,
would mitigate the impact of high volatility or
short-term market prices on customers, by hedging
more -- more than zero percent. We allow customer
supply cost to follow the long-term trend in -- in hedging prices by hedging less than a hundred percent.

In short, the hedge program is designed to mitigate price volatility while allow customer to follow and respond appropriately to the long-term energy trends. Con Edison's hedging program also includes managing our existing physical supply, by optimizing the optionality of a physical contract and co-generating facilities that we own.

Physical supply includes our own generation and contracts that generates in Upstate New York and in New York City Metropolitan area. We currently have seven contracts, one of which is for capacity only and that's with the Dynergy Independence plant, located up by Lake Ontario. The other six contracts are for both energy and capacity and their energy prices vary with natural gas prices or electric spot prices, or they vary within a floor and ceiling.

Depending on which commodity that energy prices are indexed to, we would purchase either electric or natural gas financial hedges, to limit our price exposure. In addition, we also
purchased natural gas financial hedges for our own
generations. We currently have above seven hundred
megawatt of own generation. Almost all our
co-generation facilities are producing steam for --
for our steam system.

Since many of our supply contracts
are with generating plants that are outside of our
service area, which is Westchester County, New York
City, we'll also procure transmission congestion
contracts or T.C.C.s to hedge against congestion
costs associated with delivering the energy into our
service areas.

Between our own plants and physical
supply contracts, they represent eighty percent of
current supply mix, leaving about twenty percent that
we buy from the spot market. We use both electric
and natural gas financial hedges to -- to hedge these
supplies. In total, our hedge costs about sixty
percent of our supply mix.

On this slide and the next three
slides, I will go over some hedging basics. There
are many different financial instruments that can be
used to mitigate price volatility, but I will focus
on three common-use instruments, swaps, collars, and
options.

All these instruments share some common characteristics that are associated with underlying product. It requires little or no initial investment and can be rarely settled. An example of an underlying product is Henry Hub Natural Gas or Zone J Electric. A swap would not require an initial investment, but an optional collar will, in the form of premium, unless the collar is costless. I will go over each of these financial instruments, in the following slides.

Finally, instruments can be very subtle. In other word, there is a liquid market support product. We use all of these products in our portfolio.

In this example, it's a payoff chart for a swap. While this example shows a payoff of a power swap, a natural gas swap payoff is similar. In this example, if we purchase a hundred dollar per megawatt fixed for a flow swap and the swap it's -- a hundred and thirty dollar per megawatt hour, our counterpart also see a difference of thirty thousand megawatt hour, which is shown by the bar, which when against a hundred and thirty dollar per
hour supply purchase from the market, our effect of supply purchase cost would be a hundred dollar per megawatt hour.

Conversely, if the swap settles seventy dollar per megawatt hour, which is represented by the -- the yellow arrow, we will pay our counterpart a net of thirty thousand per megawatt hour, which when added to a seventy dollar per megawatt hour supply purchase from the market, our supply purchase cost would again be a hundred dollar per megawatt hour. That swap is one of the best instruments to mitigate price volatility.

This shows the example of a purchase of a collar with a hundred ten dollar per megawatt ceiling and a ninety dollar floor. Again, this is a pay-out chart for a collar. In this example, we buy a co-option with a strike price of a hundred and ten dollar per megawatt hour and sell option with a strike price at ninety dollar.

Since the collar is costless, the amount we pay for the co-option premium is completely offset by the premium we receive for selling the option. If the collar sells at a hundred and thirty dollars, represented by the arrow, we receive twenty
dollar and a settlement price minus the collar ceiling price.

Our customers would pay the price a hundred and thirty dollar per megawatt hour. However, that cost is offset from the collar hedge entered by the company, thus fixing the price for the customer at a hundred and ten dollar per megawatt hour.

Conversely, the collars sells for seventy dollars, we pay our counterparty twenty dollars. Our customers would pay the price of seventy dollars per megawatt hour. However, there's a hedge cost of twenty, thus fixing the price for the customer at ninety dollars per megawatt hour.

If the collars sells between the floor and the ceiling, no money changes hand. The customer pays the settlement price between the floor and ceiling.

From cost perspective and when compared to a swap, the collar will reduce the potential hedging loss by the expense of low potential upside hedging gains.

The following -- this chart shows the pay-off for a call option. In this example, we
buy a call option, with a price of a hundred and ten dollar and a premium of five. If the call option sells at a hundred and thirty, we receive a twenty dollar from the counterpart, but they actually gain us fifteen dollars, because we paid the counterparty five dollar for the option premium at the time of the transaction.

The customer would pay the price of a hundred and thirty dollar. However, that cost is offset from the option hedge entered by the company. Thus, fixing the price for the customer at hundred and fifteen dollar.

If the option settle at seventy dollar or any amount below one hundred and ten, we do not exercise the option.

Our loss is limited to the premium paid for the option. In this example, the customer would pay the price of seventy dollar per megawatt hour. However -- however, there's a hedge cost of five dollar. Thus, fixing the price for the customer at seventy-five dollars.

From cost perspective and like the collar, the option will reduce the cost of potential hedging loss. In this case, limit to the premium,
but at the expense of lower potential upside hedging gains.

Our financial hedge plan is a multi-year plan that is updated annually, with the latest forecast of energy market prices and the requirements of the mass market, incorporated by various analysis that include backcasting, sensitivity analysis, and analysis. But the primary goal also considers -- is considered and it's reflected in analysis.

For example, as energy prices were coming down over the 2008 to 2012 period, overall supply costs came down, but hedging costs began to represent a larger share of these supply costs. In response, Con Edison adjusted its hedge portfolio to reduce hedging costs, while still mitigating volatility.

Our hedge plan review, adjustment, and implementation are methodical and robust. The hedge plan is reviewed at least once a year with P.S.C. staff, and it's reviewed with senior management.

In our implementation, we approach our hedges in modest increments over time, so that
market liquidity is not adversely impacted and hedge
energy costs do not merely reflect market price at a
single point in time.

Con Edison hedges electricity,
natural gas, and transmission congestion.
Specifically, the company hedges its New York City,
or Zone J ISO purchases natural gas required for our
physical supply, from both our own generation and
contracted generation, and transmission congestion
from sourcing supply from outside Con Edison service
area, with hedges using various platforms.

One example is through the
Exchange. For example, ICE, which stands for
Inter-Continental Exchange. One way we transacting
via Exchange is that there's no credit risk, since
margins may be posted daily.

Another platform used is the over
counter or O.T.C. that is transecting directly with
counterparty. The advantage of a O.T.C. transecting
is that unsecured credit is provided, based on the
company's credit rating, the limited need to
post-collateral until credit exposure exceeds a
contractual limit.

Finally, ISO platform is used to
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purchases a -- a T.C.C.s, or transmission congestion contracts. This chart shows our wholesale supply price volatility, versus the market price volatility. Based on supply mix and hedging level, as I've described earlier, it should not be a surprise that our supply portfolio is so much less volatile than the market.

During this past winter, our supply portfolio volatility was one-third of the market volatility. Our supply portfolio volatility was about thirteen and a half percent and the market volatility was about forty-two percent.

During the first quarter this year, our hedging portfolio provided a hundred and fifty dollar -- a hundred and fifty million dollar gain, which reduced the energy cost to our customer by more than twenty percent. These result demonstrated effectiveness of Con Edison's hedging program, highlighted when the market condition became extreme, like this past winter.

In summer, we believe, we have an effect and robust hedging program. We have a process in place to regularly update our hedge plan, based on performance and market conditions and we reviewed the
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plan with our regulators and senior management.

Next, my colleague, Bill Atzl, will
discuss the electricity supply with cost recovery
mechanisms.

MR. ATZL: Good -- good afternoon,

Commissioners.

I'll -- I'll brief -- give a brief
overview of Con Edison's electric supply costs
recovery mechanisms. Those mechanisms are guided by
two main principles.

First, they reflect market prices
to the extent practicable. And by that, I mean we --
they reflect market prices recognizing the region
hedge to limit volatility.

Second, they pass through actual
supply costs to customers. Con Edison does not
profit on supply and its mechanisms are structured to
pass through actual supply costs to customers, on a
timely basis.

Con Edison uses three mechanisms to
flow through its market costs of supply to
full-service customers. There is a market supply
charge and two adjustment factors. The adjustment
factor, M.S.C. One and adjustment factor, M.S.C. Two,
and I'll describe those in a bit more detail, in a couple of minutes.

I also would like to point out that in this discussion of these mechanisms, that talking about the mechanisms applicable to the vast majority of Con Edison's customers, the mass-market customers, not those that are subject to mandatory hourly pricing.

The market supply charge is based on New York I.S.O. market prices and it consists of four components. The energy component is developed for each rate class using New -- New York I.S.O., day ahead hourly prices and hourly weights based on class-specific load shapes.

Separate energy prices are developed for the New York City load zone, which is Zone J and for each of the two Westchester zones, Zones H and I. These energy prices are determined for each customer's bill, based on the market prices for that customer's billing period.

The capacity components of the M.S.C. are set based on New York I.S.O. market prices for capacity, for each six-month capability period and reflect each class' contribution to the company's
capacity requirement. Winter capacity prices are set for six-month periods, commencing each November 1st, and summer capacity prices are set for each six-month period, commencing May 1.

In addition to energy and capacity components, the M.S.C. includes New York I.S.O. ancillary service charges and the NYPA transmission adjustment charge, or N-TAC. The ancillary service charges and N-TAC are based on average monthly values of those charges, as determined from available New York I.S.O. information.

And finally, these components are adjusted for system losses. The adjustment factor, M.S.C. One, recovers on a per kilowatt hour basis, the difference between the M.S.C. amounts recovered in rates and the actual M.S.C. market cost. This adjustment is assessed in the month following the month in which costs are incurred and becomes effective with the eighth billing cycle of each month.

The adjustment factor, M.S.C. One, is determined separately for New York City and for Westchester customers and it is also determined separately for residential, versus non-residential
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The adjustment factor, M.S.C. Two, is used to recover or refund hedging costs and benefits, including the above or below market costs of purchase power contracts, costs and benefits associated with financial hedging instruments, and transmission congestion contract costs and benefits associated with full-service customers.

The mechanism is also used to recover or refund New York I.S.O. commodity-related rebills.

In terms of hedging, the M.S.C. Two includes an estimate of hedging costs or benefits for the billing month and a reconciliation of the preceding months, estimated versus actual hedging costs or benefits. The M.S.C. Two is determined separately for customers eligible for mandatory hourly pricing and for all other customers, since the company does not hedge on behalf of mandatory hourly pricing customers.

In terms of observations, Con Edison's supply prices follow market trends closely. The M.S.C. reflects actual, day ahead market prices that were in effect during each customer's billing
period, as was contemplated by the Commission in the order, in the company's 2007 electric rate case. Con Edison's supply prices are significantly less volatile than the market during periods of high market volatility, like the past winter. That was demonstrated earlier by Mr. Look.

We have identified a potential improvement, related to the one-month lag in the application of differences between estimated and actual hedging costs and benefits on customers' bills. As I mentioned earlier, the M.S.C. Two includes an estimate of hedging costs or benefits, for the billing month and a reconciliation of the preceding months, estimated versus actual hedging costs or benefits.

The M.S.C. reflects actual day ahead market prices that are in effect for a customer's billing period, which may vary from the estimated market prices used in developing the hedging estimate in the M.S.C. Two.

In the case of actual market prices that are higher than forecast, the customer would experience the higher market prices, through the M.S.C., in the current billing month, while the
benefit of the increased hedging gain is realized on a one-month lag.

So, we are exploring alternate methods of assessing hedging costs and benefits that may provide a better alignment between actual market prices in the M.S.C. and the forecast versus actual hedging costs or benefits. The challenge, however, is to do this in a manner that is equitable to each customer billing cycle.

Thank you for the opportunity to be here today.

CHAIR ZIBELMAN: Thank you.

Mr. Wentlent?

MR. WENTLENT: Thank you, Chairwoman Zibelman and Commissioners.

My name is Christopher Wentlent and I'm representing the Retail Energy Supply Association.

COMMISSIONER BROWN: Can you move closer?

MR. WENTLENT: Specifically, the electric marketing side of it.

RESA represents sixteen companies in the energy service sector, within the energy
market place. Our mission is that we support competitive retail markets, that we believe competition also will create additional innovation and that, over time, it will lead to other valuable products and services. That can be valuable not only for controlling commodity costs, but also controlling the actual quantity consumed.

If you could go to slide four, please?

CHAIR ZIBELMAN: Is your mic on?

(Off-the-record discussion)

MR. WENTLENT: Slide four?

Just a real quick overview, and most of this has been covered today, but what we think is several things occurred during this January through March time period. Record electric demand, severe cold snaps in multiple time periods, a new -- a new all-time record for winter energy demand, and -- and then couple that with high natural gas demand, that included residential heating, industrial consumption, and electric generation, in the I.S.O., as well as neighboring markets.

Okay. Some of the consequences that occurred from that scenario was that the --
we -- we -- we experienced some natural gas transportation cost constraints that drove up the price of natural gas. The electric transmission system that we talked about earlier this morning, in particular, saw a -- a -- congestion in -- in Zone F, the Albany area. The fact that oil fired generation, unusual as compared to past winters, became the fuel of choice and an economic choice in the -- and the dispatch part.

And then finally, another thing was that New York's fuel diversity, actually provided a critical benefit, in that we are rich in nuclear and hydro and oil generation and renewable generation, that provided a benefit to the system.

Lastly, conditions merited I.S.O. waiver at FERC, to request the thousand dollar cap be exempted and -- or waived, at least for a period of time.

Next slide just gives a -- kind of an overview on the -- the actual heating season, heating demand days. And the reason why I included this slide is it -- it gives a -- a look at the past five years. It also gives a -- a look at the 2013-2014 winter period. And then you can see, it
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compares a ten-year normal and a thirty-year normal.

So you can see that we -- we experienced one of the
coldest winters in the past twenty years.

To -- to take that overview on --
on the wholesale side and this next chart gives at
least a breakdown of how the current sectors, within
the retail side, are -- are composed. On a large
commercial industrial, on that particular market,
that the ESCO, some of which are RESA companies,
represent over seventy-two percent of that
marketplace and partially due to the reasons cited in
your presentation, in that there's a mandatory hour
pricing threshold. And so many of those customers
are exposed to spot market prices and need to make an
energy decision to hedge that.

On small commercial and
residential, we kind of see a flip-flop. We see,
actually those markets represented heavily by the
local utility, with a far less percentage being
represented by energy service companies.

Couple of things on product
offerings, and I'll try to break this down into two
different groupings. The C and I side and then the
residential side.
And we heard this morning, on one of the first panels, on the commercial C and I side, there are a number of offerings that are available to larger-end users. There's a -- a hundred percent fixed product. You could go a -- you could go to zero percent fixed, a hundred percent variable. And you can go a number of different types of products in between.

Some examples could be you layer in your hedge, over time. You could take a block percentage of your load and lock that in. You could take a -- a percentage or a -- a position, just on peak versus off-peak. So there are a number of different opportunities or options for a larger end user to exercise. And then lastly, you -- you do have a -- a variable price contract that could be available.

On the C and I side, it's a bit different. You generally see either fixed or a variable offering. It may have a green component to it. And Commissioner Brown asked the question this morning on what type of terms are available on fixed. Generally, the terms, at least canvassing our members, are anywhere from six months up to two to
three-year type term. And they -- they did indicate
that at least that activity interest on -- into a
fixed rate contract has been heightened as a result
of the polar vortex.

On the utility side, we just heard
the -- the presentation from Con Ed. It is a
combination of hedging and some spot market. And
it -- it is directly the result of a P.S.C. order
that occurred back in 2007. Next slide.

I wanted to show this slide because
I think it shows the tail of two seasons and maybe
helps frame some of the behavioral changes that have
occurred because of the vortex. Okay? In that, if
you look at Winter 2012, we saw record all-time low
pricing in the New York I.S.O., driven by
unseasonably warm weather that drove natural gas
prices low, which ultimately ended up being low
I.S.O. average pricing, as well.

If you compare that to Winter 2014,
we see the number for the January through March
timeframe of the -- of about a hundred and forty-two
dollars. Kind of we had the polar opposite, we went
from unseasonably warm weather to extreme cold. So,
we -- we actually, in a three-year period of time,
got to see that -- really, a market have to react to different -- different conditions.

So, a couple of points I would make, comparing variable versus fixed, okay, especially from a residential point of view. In 2012, because of that unreasonable -- or unseasonable warm weather, if you were in a fixed contract and the market continued to drop, you actually may have given up some energy cost savings because the market continued to drop. If you compare it to '14 and you were in a variable contract, versus a fixed contract, what you did is you basically were bought in to a -- a lot of price volatility that could have been prevented through a fixed rate contract.

So, I think the key point I would make is that -- that a fixed rate contract offers a couple of different real benefits to consumers. The first one is budget and price certainty. The second one is that it does provide protection against price volatility. And so, even though you could be in a market that's dropping, that individual consumer's need still may be price certainty, more than catching that last bit of gain in the market.

And then the -- a couple of other
items I would really stress, and I think it's pretty evident from -- from the morning sessions, the wholesale markets can be impacted by a number of issues. They could occur within New York, they could occur in a neighboring pool, but examples are weather, examples could be congestion in -- in either the gas or electric system. It could be infrastructure additions. Okay? So, it's really important that that -- that that -- that is factored in.

And then lastly, that real-time vice -- real-time price volatility is particularly sensitive to the utility default rate to a degree and then a variable rate that would be offered by an ESCO.

A couple of things we've done is at -- with the -- our members have done, deferred payment plans, alternative product offerings to absorb and pass through costs to a longer term. And a number of our companies have done education programs with consumers and used consumers to start the plan and -- and figure out there next strategy. Last slide.

Okay. A couple of key
recommendations we would have, one is there's
definitely a need for additional education to
consumers, both -- both on the default rate as well
as the variable rate being offered by ESCOs. That,
we -- New York needs to remain diligent on its
infrastructure initiatives. They're -- they're
moving ahead. It's a matter of continuing that --
that emphasis.

Fuel diversity is critical. This
winter proved it. We need to figure out how to
maintain that in particular, because it could be a
competitive advantage, versus others that exist in
the northeast.

And then lastly, just on the
electric and gas coordination, the need to continue
forward with -- with tightening up the coordination
between those two markets.

Thank you.

CHAIR ZIBELMAN: Thank you.

Ms. Janzen, welcome.

MS. JANZEN: Thank you,

Commissioners for having us here today.

We will --.

CHAIR ZIBELMAN: I think you have
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to turn your mic on, too.

MS. JANZEN: Thank you for the opportunity today. Today, my colleague, Pamela Dise, and I will be sharing a few overview of National Grid's hedging portfolio, our hedging program's commodity and -- commodity rate mechanisms, in addition to a review of the experience that we had this winter and discuss the prices, the hedge benefits, and the bill impacts that our customers saw.

We'd also like to describe how National Grid is preparing for the future and how we're reaching out to our customers and assisting with high bills. And as we go through this information today, Pamela and I will be passing back to each other, covering the topics that -- based upon our expertise in supply and rates.

First, I'd like to give an overview of National Grid's Upstate coverage in Upstate New York. It's a very diverse region, stretching from the Great Lakes, the West Zone, as the New York I.S.O. calls it, the Zone A, all the way across the state to the Zone F, Capital Region, where we are today.
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This wide geographic region poses a challenge in managing a supply portfolio, since they're very different market issues across these different zones, as we heard today and as we'll discuss in a little bit more detail.

We serve one point six million customers with electric delivery. And we provide electric commodity supply to almost half of that, to our customer load across the state.

And for our smallest -- smallest usage customers, the residential and the small commercial customers, we call them the mass market. For them, we offer the service of hedging or price protection of their supply costs. Our mass market customer load is over seventy percent of our total commodity supply and its supply portfolio is the primary topic of today's presentation, both the hedging protection and the bill impact discussion.

So, let's begin with an overview of National Grid's electric supply portfolio and our hedging. The objective of our hedging strategy is to mitigate volatility of electric rates for our mass market customers, while still sending the market signal, in order to encourage energy efficiency. Our
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Methodology is, like Con Ed's, to lock in fixed price swap contracts and options on a dollar cost hedging basis, adding contracts systematically, across time, diversifying all the price points.

Our current hedge target is fifty-five percent of our forecasted volumetric sales for our mass market customers, based on normal weather. Our hedge levels are higher in peak months, as we shape our hedges across the months, locking in more for periods like January and February, when prices tend to be more volatile and loads tend to be fluctuating significantly.

We continually monitor and review our hedges, analyzing their effectiveness, as well as the pricing risks and the hedge results. To manage our portfolio, we use several analytical tools to manage the volatility of our customer rates, while minimizing overall supply costs. We perform Monte Carlo simulations, running multiple trials to approximate the probability of certain outcomes, and examine the impact of our -- on our supply costs and rates, from varying scenarios of market prices, congestion, loads, and different contracts. This analysis, which is performed at least monthly,
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becomes the foundation of the company's hedging program and execution plans, as well as our longer term strategy for protecting our -- our customers' rates.

So now that you have an overview of our supply portfolio, Pamela will describe our commodity rate mechanisms.

MS. DISE: So, before we jump into what happened this winter and Margaret goes through our -- our portfolio and -- and how that actually impacted our mass market customers, again I'm going to focus on mass market customers, which is our residential and small commercial customers. It's important that you understand how the actual supply costs flow through to customers.

Similar to Con Ed, we had talked about before we -- we pass one hundred percent of the supply costs through the customers. We're not allowed to profit on it. And we also try to get the costs on customers' bills close to when the -- the costs are incurred by the company. So, there's really three components that flow through to our mass market customers' bills.

The first one is electricity supply
costs. And what that is -- is the actual -- we set, three days before the beginning of the month, the forecast market price, based on NYMEX futures. So, we set that three days going into the month and that's a fixed rate through the entire month.

The next one is the new hedge adjustment. Those are the hedges that we're talking -- that we enter into and Margaret's going to talk about that in a little bit. And we actually use the same market price forecast, so we're lined from the market price forecast period that we're looking at. And based on that market price forecast, we're able to determine what the value of those hedges are. Those value -- the value of those hedges are socialized across all of our hedge commodity customers.

And then there's the reconciliations. This ensures that we true up, exactly to our commodity expense. And there's two basic different true-up mechanisms. One actually trues up the forecast to the actual market price, both in the -- the electricity supply cost and in our hedging forecast. And then there's a -- and that's done on a two-month lag and it's also socialized
across all of our hedge mass market commodity customers. And then there's also a two-month lag true-up between actual commodity revenue and actual commodity expenses.

So, those the components of the electricity-commodity side of customers' bills. I'll turn it back to Margaret to go through the portfolio.

MS. JANZEN: So, with that overview, we could turn to what happened this winter. This is something that we've seen several times today, that the wholesale electric market saw an unprecedented increase this winter.

Here, we're -- we're showing Zone C, the Central Zone and the increase of the hundred twenty-two percent over last year.

We had seen some market and price increase in the winter prior, from the relative lows of the Winter '11 or '12. However, the market price increases, as seen here, was much larger and the monthly average prices more than doubled over the prior winter. And it wasn't just Zone C, it was also Zone A, all the way in the west as -- as well as Zone F significantly impacted.

So, with this huge increase in
market prices, how did our hedge perform? Well, going into the peak winter months of January and February this past winter, we had locked in prices for sixty percent of our forecasted mass market customer load at a hedge target, which had been increased over the prior winter and spread across different zones. Our winter hedges included physical hedges, seen here in the blue, and as well as swap and option contracts layered in over many months prior to the winter.

These financial hedges for the winter peak months of January and February produced over sixty million dollars in savings for mass -- mass market customers, helping to offset the increase in market prices.

And now, Pam will take us through those market prices and how they were reflected in the bills.

MS. DISE: So, what this chart is trying to show is there's basically three different lines. The blue line in the middle shows the delivery component. And this is average across all of our upstate zones, for residential customers. So, you can see the blue line is -- is relatively flat
and -- and very stable.

The green line, below, flows through those commodity components that I had talked about before. The E.S. costs, the new hedge, and all the reconciliation mechanisms. And you can see it's much more volatile and especially over this last winter when you get down into the December, January, February, and March timeframe. You can see how it -- it jumps around.

I -- I think I neglected to mention earlier that when we do the forecast for the market price and pass that through the customers' bills, that is done on a zonal basis. So, the market price forecast in -- in Zone A will be different than the market price forecast in Zone F. All of the hedges and reconciliation mechanisms are done on a -- on a socialized basis. Next slide.

And so this is a -- this is a different chart that basically shows what happens this winter. It's broken in to two components. Right on the top hand side, that's Zone C, which is our Central Zone. Down below, is Zone F, which is our Capital Zone, where we are today, and it's representative of six hundred kilowatt hour
customers, what we use for a typical customer.

So, what you'll see here, again, is the blue is relatively flat. And you'll see the top on the green, for the Zone C is -- is jumping around. And you can see in March, it goes much higher and -- and both the Zone C and the Zone F -- and I'll explain that on the next slide because it has to do with our reconciliation mechanisms and our lag.

If we could just kind of revisit what happened over the winter, we've learned through the whole day, you know, the -- the wholesale market prices kind of jumped all around in the January and February timeframe. And if you remember how I mentioned how we set our rates in January, we set them at the beginning of December.

So, we set those rates. And what happened in January -- January was very cold, the prices stayed very high for -- for a long period of time during January. So, we set the market price too low, right, based on the -- the NYMEX futures, as well as the value of the hedges. That gets reconciled in the March timeframe, so that's why you see it jump up a bit there.

So, I -- the other thing I wanted
to mention on this slide, I'm sorry, you can see --
and it was -- it was talked about earlier from --
from other parties during the presentation --
presentations today, you can see between January and
February, those charts are relatively flat. That was
the -- the event that we actually deferred thirty-two
million dollars, when we saw the February prices
going really high, and we asked to have a deferral,
the thirty-two million dollars to mitigate that in --
in the customers' bills for the month of February.
And that's deferred for future recovery.

Can we go to the next slide,
please?

And so, what's really happening and
why you didn't see the big jump up in January and in
February, which we just talked about and -- and why
you're seeing it jump up in March, has to do with how
we bill and our reconciliation mechanisms. So, we
talked about it being forecast on a monthly basis,
prior to, and then reconcile two months later. And
that's what this chart is showing.

On the left-hand side of the
chart -- this happens to be Zone C, which is our
Central Zone. So, on the left-hand side of the
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chart, the blue bar is our forecast in market price. So you can see that a little above six cents, right around seven cents.

The green is our hedges, so the value of our hedges for that month was a benefit to customers. So it actually reduced their electricity supply costs for that month. And then the January reconciliations were a -- a small benefit for that month. And we're reconciling costs and revenue, in actual forecast for November, so that's what's flowing through here.

The gray shows you what actually happened to the commodity prices in January. If we actually charged what happened in the market, in January, we would have been charged in that gray bar.

Now we get to March. What's happening in March? Again, same thing. The market price forecast is set three days before March. And you can see where that -- that price comes in, right around the eight cents, but then you see a huge reduction on the hedging side, right. That's the reconciliation of the hedge. Remember we -- we -- I said before, we line -- we align our forecast, both for the market price, as well as the hedges?
Well, so we undershot what the price was going to be for January, based on where the futures were, right three days before. That turns in to undervaluing what those meant -- those hedges would've been, so you see that in the hedge when you see the March. And then the March reconciliations, represent the difference -- the large majority of it is the difference in the gray bar for January and what we actually charged customers in January.

I'm going to turn it back over to Margaret and we're going to talk about some observations for this winter and -- and what we're going to plan on doing, going forward.

MS. JANZEN: First, one of the things we observed, in addition to the cold weather, that it -- that was the driver of the increase in the natural gas prices, which impacting a large portion of the New York generation, depending on that fuel, and then the increased electric load, in addition to the gas prices, were the driver of the power prices across the state and, indeed, the whole northeast region.

These natural gas factors were compounded by the electrical congestion that we
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experienced across the central east transmission
interface, as described by Wes Yeomans, and drove
those prices in Zone F up to the record levels.

The second observation we made was
that the volatile winter prices could vary greatly
from the forecasted market prices, especially when it
happened within the month after the rates had been
set. And this created a difference, which should
significantly increase bill volatility, when it got
reconciled on a two-month basis.

And then related to that, we also
saw that the regional spreading of the reconciliation
of that forecast difference, then could start --
could -- could increase volatility in certain zones,
more than others.

Fourth, we -- we observed that Zone
F's congestion component, that we described a bit
today, earlier, became much more volatile during the
winter, exposing the Zone F customers to high
congestion spreads, on top of high underlying energy
prices.

And finally, our -- our hedges
yielded gains as market prices rose. They yielded
eighty-six million dollars for the period, November
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2013 through March 2014, a great benefit for our customers. However, the benefits were spread across all the zone and, therefore, diluted the effectiveness to the Zone F customers' price protection.

So, after the experience of last winter's prices and rates and analyzing the contributing factors, we undertook a thorough review of our supply portfolio hedging and our commodity rate mechanisms. We are concerned that future prices, as well as month to month impact on our mass market customer rates. To that end, we have developed a comprehensive solution that we propose to better manage volatility from both a supply portfolio and from a commodity rate mechanism perspective.

So, looking ahead to next winter and -- and also to the summer that is right before us, we continue to be concerned about market rates, since the fundamental infrastructure issues that constrained the supply still exist. We continue to vigilantly monitor the market and our hedges and have diversified and increased our hedging levels for the upcoming winter, as well as for this summer.

Enhancements to our supply
portfolio include separate hedging for Zone F, that will better allow alignment of those hedges to that zone. But increasing the hedges is not enough. We need more tools to better manage volatility on a zonal basis.

So, the company has developed and filed, just yesterday, proposed modifications to our commodity tariff. I'll describe those changes. First, we propose to provide zonal hedging rates, in addition to the existing zonal market rates, the E.S.C., so that the hedging benefits or costs can flow through to the specific zones that the hedges are -- are protecting. In this way, Zone S -- Zone F hedges would be attributed specifically to Zone F rates.

In addition to zonal hedging rates, we also propose to reconcile by zone, the difference between the forecasted and actual market rates. This will allow the company to reflect the actual zonal prices, ensuring that those customers receive the credits or charges incurred in that zone.

We've also proposed the flexibility to delay reconciliation recovery, so that the company has more flexibility in the timing of its
reconciliation of revenue and expenses for its mass market customers. In the case of extreme market volatility, the company would have the ability to spread out monthly reconciliations over two or more months, rather than the current one-month period.

In summary, the zonal hedging rates and the zonal reconciliation of forecasted rates work together with the separate hedging portfolios, with the tariff flexibility and the reconciliation recovery, would allow the company the necessary tools to better help mitigate the rate volatility for mass market customers.

In developing our proposal, we researched best practices of other utilities and benchmarked ourselves against others. We also performed analyses to determine the impacts of the various modifications and how they would work together.

We ran a backcast analysis, using actual market data, for several scenarios, to determine what modifications could have effectively mitigated the high rates last winter. In this analysis, we did exclude the thirty-two million dollar deferral that we had in February, in order to
better determine the full impact of what the winter prices would be on the retail rates.

Among these scenarios, we analyzed a separate supply portfolio, including specific hedges for Zone F, along with zonal hedging rates to allocate the benefits and costs to those zones. In addition, we modeled the change to reconciliation tariff, which would have provided flexibility in the months for recovery of the reconciliations, a tool that might have been used when January market prices skyrocketed midmonth above the forecasted rate, thus impacting March with the large reconciliation.

The chart on this graph shows -- on the top right, shows the backcasted typical residential bill, on a backcast basis, for Zone C, with the green and blue bars, and how this scenario for modifications could have mitigated month-to-month bill impacts. This is seen in contrast to the black line, which is the actual bill impact that we did see this winter.

The backcast shows that the volatility for March and April bills could have been significantly mitigated with the proposed modifications. And this would have allowed also for
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a modest increase over the next two months, to recover the balance of the reconciliation, once we exercise the tariff flexibility.

On the bottom right, the backcast analysis for Zone F, with the scenario of modifications, shows that the month-to-month volatility could have been significantly mitigated from December through April and would have been fully reconciled by April, if we had exercised the tariff flexibility on the reconciliation recovery. According to our backcast analysis of this scenario, our customers in Zone F could have benefited from over thirty percent reduction in the actual costs that they saw for January through March.

As a note, in another one of our scenarios that we analyzed, we found that an increase in Zone F hedges was not enough to significantly mitigate rate volatility. It took both tariff changes, in order to make any significant difference, the zonal rates for the hedging and the reconciliation, in addition to the tariff flexibility, on the reconciliation recovery.

And now, Pamela will cover what National Grid is doing for our customers that are
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experiencing the high bill impacts.

MS. DISE: I know the red light's on, so I'll just take a couple of minutes to go through some of the highlights of the next slides because I know these slides have been before the Commission before, so that -- they should look very familiar.

The company recognizes this winter has been very difficult for some of our customers. We know the prolonged extreme cold temperatures that we've been talking about, the volatility of electricity market, as well as the high prices that they're seeing, really makes us want to reach out to -- to the stakeholders and -- and -- and -- and work with them. So, the next few slides are going to go through some of the things that we're doing.

Okay. One of the -- one of the most valuable tools that we have are -- is our -- is our consumer advocacy group. This is the -- the outreach group that actually works with some of our low-income special-need customers and are offering first-of-its-kind customer assistance, sorry, expositions to connect customers with all low-income organizations in a single location.
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Credit and collections programs,
they've increased the outbound calls and -- and
payment agreements, different payment options that
we're offering customers.

The budget plan was heavily
promoted. The budget plan, in itself, actually
smoothes out customers' bills, so where it's hard to
see spikes, all they need to do is -- is call in and
ty they can actually take those and actually flatten
their bills going out.

And also, we continue to promote
our energy efficiency programs, which will have a
permanent reduction in customers' bills.

Margaret has also talked about the
hedging strategy, so I won't go through that, as well
as the thirty-two million dollar deferral, which I
also won't go through that, too. We've already
discussed that.

And so, the last slide, actually,
U.I.U. did a really great job this morning going
through this slide for me. This is the emergency
customer care program that is flowing through our
customers' bills in May. U.I.U. mentioned it. It's
a -- it's the corporate contribution of a million
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dollars through our Care and Share Program, as well
as one-time emergency payments applied to customers'
bills, two hundred and fifty dollars to about four
thousand of our HEAP eligible customers and another
twenty dollars to our -- about a hundred and ten
thousand low-income customers.

And again, I already mentioned the
targeted outreach to low-income customers.

CHAIR ZIBELMAN: Thank you.

I have a few questions, so let me
just start with you, Mr. Badgley.

We -- this is a question I probably
could have asked others, but let me see if -- if you
know if there's an answer, or if other panelists have
an answer, that would -- that would be terrific.

One of the things that occurred
during the course of today, we've been talking about
the fact that the polar vortex, the cold weather has
created obviously huge demand, which resulted in high
prices. Is it possible to backcast that and figure
out, if we had sort of normal winter weather for this
region, what the prices would have been like and how
much of this scarcity is driven by a weather event?
I'm not saying that this was a one-time, because I am
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concerned that it might not have been a one-time, but
is there a way to backcast that and figure out how
much volatility was driven by unusual weather as
opposed to that we're starting to see that we're
eating up our excess on distribution supply?

MR. BADGLEY: I think that’s a -- a
very good question and I, you know, am not too
familiar with the ideas. I'm sure that there are --
are plenty of people out there who are -- who are
looking at -- at that kind of thing and, you know,
something that would be of value.

You know, it's -- it's hard to tell
because, you know, there are just so many variables.
You know, especially in the -- in the spot market
that we're covering from day to day, so many
variables that might play into the pricing and kind
of, you know, bringing it -- bringing it to a -- a --
you know, a normalized weather condition. I -- I
think it might -- it would give you some -- some
ideas of where the price may have been, but probably
has some limitations, as well. But --.

CHAIR ZIBELMAN: Okay. Any --

anyone else want to --?

MR. LOOK: Yeah. I think that
would be a very difficult exercise because while we can limit our exercise to study just the northeast, the difficulty with this incident is -- is throughout the whole U.S.A. So it's very difficult trying to normalize and try to -- to find a -- a winter in the past, or something like that, to -- to try to -- to -- to gage this what would the volatility be under sort of more of a normal winter.

So, again, if it's this event, which is limited to the northeast, I think we could -- that exercise is probably more doable. But because it's so vast, so -- it's become very difficult.

CHAIR ZIBELMAN: Okay. Mr. Wentlent, for -- a question for you because you were talking about fixed products and I -- I think you probably heard the early conversations today from the consumer panel about the fact that they're looking at probably three to five years, but there's an issue potentially about your ability or -- or the willingness of retailers to offer fixed pricing to mass market because of credit issues and/or to smaller consumers.

Is that -- I mean, from your
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perspective, is -- is that a limiting factor or is there a limiting factor and what -- what might that be, in terms of the willingness of retailers to -- to offer fixed pricing?

MR. WENTLENT: And I'm speaking just for our members.

CHAIR ZIBELMAN: Your group, right.

MR. WENTLENT: Yeah. They're -- they're definitely willing to offer fixed product pricing. And the term length is up to two years. Two to three years for residential. As we heard this morning on the panel, you could see C and I type deals that could go out to a three to five-year period of time.

So, I -- I do believe that a -- a fixed price offering is available and would be available. Would it be for every single ESCO in New York, I'm not sure. But I -- I -- I definitely believe that it -- it is available.

CHAIR ZIBELMAN: But there -- I mean, for obvious -- is -- there's a credit premium associated with that. Is there? In terms of pricing, if we were to look at pricing, from residential to commercial, would we see reflected in
that a credit-risk premium?

MR. WENTLENT: I -- I --.

CHAIR ZIBELMAN: From the perspective of the ESCO?

MR. WENTLENT: Okay. I -- I think you would see a premium for the fixed contract.

CHAIR ZIBELMAN: Right.

MR. WENTLENT: I -- I think I'd have to go back and check on the credit piece, because it -- it may vary by company. And I honestly -- I don't know the answer.

CHAIR ZIBELMAN: I mean, one of the things that -- that's striking me, and I -- I just had a question, I guess, for the utilities. You know, we -- we -- both of you -- both companies have talked about the fact that, you know, you're trying to manage volatility through hedge products. And one of the things that may be a difference is that because you don't have a fixed obligation, you don't have, as I -- a market-to-market obligation, right, to -- to market against any value at risk, which if you had a fixed obligation on the sale side, you would have to worry about, you know, where the price -- what you would
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need to do to cover that fixed obligation.

And so that -- I'm just curious, in terms of that, is that the value, obviously, of having hedges and not having a fixed price, is that there's not a tendency to over-hedge, in the fear that if you're, you know, that your prior price would -- would -- has enough cushion in it? Is that -- is that a fair statement? But I'm curious as to how then, you make a determination of how much you should hedge around volatility and what's the -- what do you benchmark against, if it's not a internal value at risk.

And the only reason I'm asking that is I'm kind of curious about this question of whether fixed prices would result in lower rates or just having good hedges in place result in lower prices, bills to consumers?

If you follow my logic, which may not be logical, but --.

MR. LOOK: Maybe I'll take -- I'll take a shot at this. I'm not sure.

CHAIR ZIBELMAN: I'm -- I'm curious.

MR. LOOK: Yeah.
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CHAIR ZIBELMAN: I mean, if you --

MR. LOOK: Yeah.

CHAIR ZIBELMAN: -- if you had a

fixed price, you would have a -- you had to risk a

loss -- you would have potential losses.

MR. LOOK: We do

market-to-market -- we do monitor our portfolio every

single day. That, we do.

The way we hedge, we -- we do also

do an analysis, look at how our portfolio -- total

portfolio, versus the market over time. And it

really come down to the -- to the -- the very

difficult exercise because in trade -- there's a

tradeoff between volatility and cost. There's a --
you can hedge a hundred percent, you get no

volatility, but that's going to be very costly. So,

there'd be some -- some tradeoff there. There'd be

diminished return here.

So, we tried to, I guess, look

for -- also Commission guidance here and we felt

that, within that range, between fifty. We also have

option to -- you have a option. We get up to as high

as seventy percent hedge. So, within that -- we

think we're in pretty good spot already of -- right
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now.

So, it doesn't mean it has to be that case. We'll always continue to always monitor our performance, so we can -- 0:00:17 changing.

COMMISSIONER BROWN: Audrey, can I follow up on that?

CHAIR ZIBELMAN: Yes, certainly.

COMMISSIONER BROWN: It -- it was a question for Con Ed and it just flies right into here.

If I looked at your pie chart correctly, on hedging the supply mix, an awful lot of that looks like legacy PURPA contracts. So, it really hasn't been an affirmative hedge. It has been you were hedged from contracts that were signed fifteen -- twenty years ago. And I see an awful lot of them that are expiring in 2014, '15, '16, and '17.

So, I think the question that Audrey was asking, which is how are you going to decide how much your hedge is really going to come to the fore for Con Ed. I don't think Grid. They kind of got rid of those contracts a long time ago. It's really going to come the fore, because you're going to be losing, it looks like literally, thousands of
megawatts of hedges over the next two to three years
and quite a few this winter, it sounds like.

MR. LOOK: There's -- the first contract is expiring,
coming up is the Selkirk contract expiring the end of
August this year. The other contract will remain
through the next winter.

You're absolutely correct. That's
one of the thing that we've been doing -- always been
doing is the supply planning. And one of the aspects
is that beside the volatility, we recognize the fact
that value -- that physical -- or physical asset
would bring to the table, as far as reducing
volatility. And that, we will be looking into how to
replace those contracts as they expire.

COMMISSIONER BROWN: I got others,
but you were on a roll.

CHAIR ZIBELMAN: Well, yeah, I --
I -- and let's -- I want to talk to -- same question
to Grid, and actually the same question that Garry
just asked because that was exactly one of the
question I have, is, you know, we're -- we've been
talking about financial hedges. What about physical
hedges and I'll just throw this out.

And how does this play into this
idea of should the electric utilities or the ESCOs be
looking at physical hedges in the form of firm
pipeline capacity, to drive demand, to drive down the
volatility around gas? Is that -- I'm not
suggesting -- there's -- there's nothing behind this
question other than a question to ask you to get your
thoughts on.

MS. JANZEN: If I could go back to
the question about the hedge levels and how we
determine it, and the fixed pricing. To the extent
that the -- the -- the forecast gets updated and
nature of the load that we're serving has a certain
amount of migration in it, and as we do our scenario
analysis and look to see of the variability of that,
it -- there's no perfect hedge level.

It's -- it's more about sending the
price signal and who is the protection for and -- and
looking at the customer set we are providing this
protection to, sending that market signal on a
monthly basis. However, mitigating it with a portion
of it offset on a monthly basis, has -- seems to have
the right mix of -- of balancing the two.

And then as well as -- as King had
pointed out, the -- the cost of hedging themselves.
The options -- the -- the -- these, basically, insurance premiums, locking in swaps, which tend to be over multi-months, has a tendency to flatten out rates and then, therefore, take away that market signal.

So -- so, to the extent that that is something that is very dynamic, the -- the loads, making sure the -- the correlations are making sense, the right hedges.

But to the question of the financial versus physical hedges, at one point, Niagara-Mohawk had quite a bit of physical hedges in the form of nuclear and -- and hydro. And -- and as those hedges came off, on a -- on a predetermined basis, the -- when the company was seeking an effective low-cost execution manner, in which to hedge, the -- the financial markets lend themselves to it. We are able to leverage good credit ratings with -- and -- and can use a standardized contract. So it effectively allows us to -- to lock in prices and -- and to do that on a low cost and -- and effective manner on -- on a relatively short-term basis. It takes -- it doesn't take much to -- once all the credit terms have been established, it's very
easy to execute.

But to the extent that the physical hedges, themselves, you know, have -- have, indeed, benefits, especially with the locational benefits, indeed, that's something that our company does look into and -- and -- and does -- would consider as part of the portfolio because it can fit into -- fit into -- for -- for -- for a firm commitment, it -- it would fit well into the portfolio.

CHAIR ZIBELMAN: And Chris, let me ask you the same question. In terms of hedging strategies of your groups and also the -- you know, the portfolio approach, are you -- are you looking at -- I mean, do you -- well, first question, I guess, is -- is it a combination physical and financial? And then, secondarily, is that driven by the willingness of the demand market, which I think the problem, I think we can all sort of observe, is when prices are dropping, consumers are lulled into a feeling, like why would I lock into a price if prices are going down and then when the prices get up, they -- they wish they were, but then prices are higher, so the cost of locking in a fixed price just went up.
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And so how do we -- I guess, that -- to me, the ultimate question is how do we establish, recognizing that these prices are always going to go up and down, a -- a culture of consumers really thinking about that there's a -- a value in having a fixed price for energy, even if it appears in one season or another, they're paying too much because overall they may be -- there's a lot built into these assumptions, but that's my assumption, that there's value there against price volatility, but there's a reluctance when prices are low and a difficulty when prices are high.

So, the question is how do we overcome that and what are your thoughts?

And I'll throw that out to everybody. One is do you agree and secondly, what's your thoughts on what we might do?

MR. WENTLENT: I think on the -- on the actual physical asset side, there are some of our companies that actually own physical assets in New York and in the Northeast.

CHAIR ZIBELMAN: So, they have a natural internal hedge?

MR. WENTLENT: So, they do have
a -- a natural internal hedge in a -- in a volatile situation.

The -- the -- the other thing that -- that was talked about this morning was is there a need to look at some of these fuel types differently, going forward. Okay? And it may not be a -- a long-term hedge arrangement. It may be a different type of market product that needs to be considered. So those assets are in the market, a fuel -- fuel firmness type product or a special winter capability type arrangement that would allow one to keep fuel diversity in -- in the market place.

It provides somewhat of a hedge anyways, in the winter period, because that asset's functioning. And then you still, I think, gain some of the other advantage of allowing the financial markets to be very competitive on that -- in a month-in/month-out basis that you may want to -- to maintain.

CHAIR ZIBELMAN: I think I'll think about it for a minute, but I'll turn the mic over.

COMMISSIONER BROWN: I just had a couple of -- couple questions.

Chris, one -- there was a bullet
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that you actually didn't really expound on, because you ran out of time.

MR. WENTLENT: Yeah.

COMMISSIONER BROWN: Which was talking about uplift and maybe this is one for Wes, as well, to think about.

Did we see a rise in uplift and -- what the bullet said is uplift's really bad because ESCOs that hedged still have to pay the uplift cost. Whereas, if it was actually in the market price, they would have benefited by the fact that their -- they had hedged themselves and they lose that benefit of the hedge, if I understand the concept correctly.

And I know it was a big problem in the early part of the market, that a lot of costs got stuck in uplift, that really should've been in the market and NYISO's done a great job of switching those. But did we see that phenomena again in January through March, where uplift costs increased because of the strange circumstances that were going on?

MR. WENTLENT: I -- I actually think you -- you saw that more in -- in P.J.M than you ended up seeing in New York. There was at least
a concern, initially, if units had to bid above the
thousand dollar bid cap, that that would be handled
through a discretionary acts committee decision at
the I.S.O. and then that cost would be allocated back
through -- through uplift.

Kind of the -- the principle being
that, if -- if you had an end user who had hedged,
okay, and was in a fixed contract, then you have an
uplift charge that may not have been hedgeable. And
so it -- it acts as a deterrent, in a sense, for
that -- that end use customer. That -- that's kind
of the principle.

CHAIR ZIBELMAN: Wes, go ahead.
You can sit down.

MR. YEOMANS: Yeah. Well, I'm
hoping not to stay here too long.

CHAIR ZIBELMAN: Welcome back.

MR. YEOMANS: Actually,
unbelievably, the uplift in January, and it was
significant in some -- some other R.T.O.s, in New
York, was actually negative. The state-wide uplift
for January was negative. There was a positive cost
component for the generator supplier, not a huge
amount, but that was offset by some B.M.T. error,
some balancing market congestion residuals in a real-time market and for the -- the residual loss impact, that's usually negative or a refund. So, the two refunds offset the power supplier positive piece. The net for the state, I -- I believe was -- was just slightly negative for January.

COMMISSIONER BROWN: So, hopefully, there'll be no phenomena that happen this summer -- or this winter that's going to discourage hedging by people next year because of that fear? That's what I -- hopefully, I'm hearing, which is good.

Okay. And Patrick, I just have a really generic question for you.

Can you explain to me how a six dollar commodity price turns into a hundred and fifty dollar product price in New York City? What happens? Where -- where are the steps that these costs go up, because obviously congestion, et cetera? Give me the layman's version.


So -- yeah, you know, clearly congestion is the big driver and basically, you know,
when capacity is -- when someone who holds firm
capacity, you know, turns that over to the secondary
market, you can essentially get into a situation
where, you know, that -- the person who can own
that -- who owns that commodity and owns the -- the
pipeline capacity, can, you know, chew the --.

COMMISSIONER BROWN: Like having
Springsteen tickets.

MR. BADGLEY: Right. Right. Can
sell what the market bears, yes, so --.

COMMISSIONER BROWN: He's just in
town, that's why I said that.

CHAIR ZIBELMAN: Did you have
tickets?

COMMISSIONER BROWN: No. And they
would've cost more than face value if I wanted them,
so --.

MR. BADGLEY: Right. And -- and --

CHAIR ZIBELMAN: Okay. Go ahead.

MR. BADGLEY: -- you know,
because -- because natural gas prices aren't --
aren't regulated, you know, that -- that -- that can
go up. It -- you know, as you saw this year in
the -- in the ICE example, once that -- that roof was
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lifted, you know, it certainly -- certainly started
happening pretty quickly thereafter, so --.

COMMISSIONER BROWN: And it's
basically, because there's consumers that are willing
to spend that, to get the product.

MR. BADGLEY: Right. Exactly.

Because -- you know, they may -- they may face
penalties of their own, if they're -- you know, if
it's a generator that's not able to run, you know, if
it's an -- an L.D.C. that's not meeting its -- you
know, meeting what it needs to meet. So, it's a --
yeah, you know, in some cases nobody, you know, would
be crazy about paying that price, but --.

COMMISSIONER BROWN: So, who's
making the money?

MR. BADGLEY: Well, you know, it
can be -- it can be a marketer, you know, someone who
owns that capacity or it can be, you know, the -- the
commodity owner, the -- you know, in some cases,
the -- if a producer would own that capacity, then
the -- the producer, you know, has that power.

CHAIR ZIBELMAN: So, to follow up
on that, the solution against that is to have the
players who have the obligation or -- or -- or
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responsibility, to have someone else earn more firm capacity; right?

MR. BADGLEY: So -- right.

CHAIR ZIBELMAN: Who -- who -- whoever.

MR. BADGLEY: You know, they --

CHAIR ZIBELMAN: I mean --.

MR. BADGLEY: -- you know, holding firm capacity, you know, would be a solution. It's a -- you know, a -- as we talked about today, you know, it can be a -- a pricier solution. You know, the -- the addition of capacity as, you know, more pipeline capacity being built into these -- into these heavy demand areas.

CHAIR ZIBELMAN: Further questions?

No?

Okay. Well, thank you to these panelists and -- and everyone across the day. I -- it's been certainly an informative day. And I really appreciate everyone's attention and -- and the time you spent in delivering the information.

The -- just my observations, and these are just sort of initial observations, but also some, probably, requests going forward.
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It does seem to me, and maybe this is a question as well, but it does seem to me we are entering into a new time. And this is a cyclical industry and we -- we do have periods where we have excess supply and then we seem to be entering into a period where there's generation retirements and perhaps more demand on certain parts of our infrastructure, like the pipeline infrastructure, than we've had previously.

And it -- what I'm concerned about and something I know that, Garry, you've been focused on in the last several years, is the fact that we're -- as for the electric industry, of course, the obvious points become more and more dependent on a gas infrastructure and as we heard a little bit today, is the gas infrastructure's dependent on back-up oil, which may or not be there because the demand is intermittent, we need to really start thinking about the intersection of these industries and really thinking about it on a long-term period, is -- one is where's demand going in -- in the state, how that potential demand and requirement in pricing can be effected by what's going on elsewhere because we're not an island, and really kind of getting ahead.
of it, because if we're not ahead of it, we're constantly going to be behind the eight ball. And that means really looking at, on -- on I think a fairly deep level, the infrastructure needs of the state moving forward. And that's not just electric infrastructure. Obviously, it's an important part, but also gas infrastructure and I think it's also important that we consider the back-up oil infrastructure and -- and other fuel types, and how all these need to fit together to be in a position that these weather events don't drive these type of price events that either really hurt consumers, or -- or potentially drive other businesses out of business.

And so, I think that one thing that I'm -- I'm taking away from this is -- is that it is going to be very important that -- from a -- a collective standpoint, that we do get our arms around what's going to be the requirements in this -- for the state, over the next ten to fifteen years. How do we maintain a fuel diversity, which I think everyone's identified is of value, and what we need to build out as infrastructure.

So, one of my takeaways from this
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is -- is really for the -- probably for staff to start looking at this issue, thinking about how we move it forward so that we have -- we are looking into -- not the rearview window, which we all like to do, but quite frankly, it doesn't help us that much. It helps us a little, but we really need to look forward and see what the needs are and really start make -- thinking about what does that really mean in terms of investment and how do we actually incent that investment in the most efficient way. So, I think that -- that's sort of one big takeaway.

I think the other takeaway I have is, during this period, because we're not going to be able to solve these types of issues overnight and there's always going to be a potential element of -- of infrastructure scarcity, is how do we protect consumers better, particularly the mass market, but I think we even heard from the commercial/industrial that, you know, this may be hurting them in different ways.

For example, just even the fact that they're not -- they're having to run their systems harder and longer because of interruptability or because -- things like that, is really thinking in
terms of how do we manage that price volatility, what kind of price hedges -- we're, you know, looking again, as I said the utilities are doing it already and I'm pleased to hear about it, is looking at your hedging strategy, see if they're adequate for these new times.

But I think also, you know, we really look -- need to look at market products. And frankly, look at, again, fixed products, whether offered only by ESCOs, whether we go back and look at whether utilities should offer fixed products, what does that mean. And I know, you know, as part of our REV docket, we're going to -- we are going to be looking at all of these elements because we -- this is a big piece of how to animate the retail markets better, but also to drive efficiency and -- and drive out some of the natural volatility from the standpoint of what kind of consumer products can be offered.

But -- but I -- I would, you know, appreciate folks' thoughts on both of these issues. You know, how -- driving infrastructure investment, how do we use demand to drive that investment, and what are the best vehicles to get there, in your
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comments to us because it's -- it is -- this is a
cyclical industry and we'll -- we'll -- I think we'll
never stop it from being a cyclical industry, but in
the end, I think it's really important that we think
about, from the consumer perspective, how do we
protect them from these boom and bust cycles so that
they can -- electricity not only remains affordable,
but the price remains reliable so people can budget
around it.

So, that -- those are sort of my
two big takeaways, other than the third one, which
was it was a cold winter. But that was obvious.

Comments from any of my other --
any other commissioners?

COMMISSIONER BROWN: No. I just
want to -- one thing I didn't get a chance, with
Grid, just the simple look at not socializing the
hedging, if it really hits one zone over another, is
it going to make for improvement, hopefully in
2014-15. And I think that's got to be -- there's got
to be two efforts here.

One, is the near-term effort. What
can we do in the next six months to make things less
likely to happen if we have a repeat of events next
And then the second is the longer-term, kind of what Aubrey just described, which is what are we going to do on a more permanent basis, as the dynamics of the system change. And electricity and gas are obviously becoming incredibly more interdependent. If coal plants close throughout the Midwest, it's got all sorts of ramifications, so there's just a lot of longer-term questions that we need to think about.

You know, as having been an oil and propane customer for the last twenty years, I'm entirely comfortable with the concept. Every winter, I have to decide whether to buy ahead or ride the price. That product's been out there forever and some winters you win and some winters you lose. For some reason, that hasn't caught on in some other fuels. I don't think it's really a matter that consumers couldn't understand it. It's just I don't think that product has generally been there for people to move forward.

So, that's -- and I know -- as a matter of fact, Doug Elfner sent me an email after some questions this morning. And I'll thank Chris
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Wentlent and the ESCO community. There seems to be a lot more fixed-price product emerging, maybe as a result of this winter. Maybe a lot of consumers said wow, I should have that option and the ESCOs are responding with that option.

So, I think we need to take a look at what we need to do this year and we need to take a longer-term look. So, those are my initial thoughts.

COMMISSIONER BURMAN: Madam --

Chair Zibelman, it's very hard to put on a truly substantive technical conference such as this, so I thank you and all of the staff for what you've done to put this together so successfully.

I also applaud all of the panelists and those members of the public, who have taken the time to participate in this conference today. And I welcome their comments that can be formally submitted after this conference.

I did want to recognize, from FERC, Jeffery Dennis, who came here. I very much appreciated that and the coordination from FERC. I know that FERC had the technical conference back on April 1st and that there'll be comments coming in, I think, up until today, right, is the closing. So I
looked forward to hearing what will come out of that.

I know that at the time of the April 1st technical conference, Chair Zibelman had testified there and talked about looking at things that could be done, both on a short-term and long-term process. And I know that, publicly, that Chair LeFleur had -- had echoed her support for that, so I look forward to that continued coordination.

But I'd also like to recognize, you know, what I affectionately term as Wes the Rock Star, in New York. And I'm sorry to publicly call you out on that, but, you know, you once again have proven -- you know, I tried to trip you up, by looking at your testimony back on April 1st and, you know, you did stick pretty much -- there was not one thing that you said both -- actually, in your testimony and in your PowerPoint, that I could say, you know, you've done something differently. You really have shown just your due diligence and really how much you work for the benefit of the people in New York. And I'm really just very glad that you have your eye on the ball.

And you know, the I.S.O. has a big role to play in the coordination and the planning, on
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a going forward basis. And I know that, you know, we really need to look at, regionally, the coordination and the lessons that have been learned. And you know, there was a lot of things that we can -- that we know. We know that the weather has been extreme. We look at the last thirty years and have to plan for that, but we also -- when we look at that, we have to try to figure out all of the different things that we can do.

But some of the unknowns are what are the behavior patterns that are going to happen. And -- and we can't predict that. We can only make some assessments and try to work through that. But it's not just the weather. I mean, we've had cold weather, we've had hot weather. We've got a plan for the upcoming summer and the heat waves that may happen. And we've got to try to figure all of that out and adjust to that.

For us, our number one priority is reliability, keeping the lights on. And it's important to have short-term goals that are also focused on the long-term goals, which is, you know, a lot of this dovetails into the REV proceedings. The track one and the track two, a lot of the hedging
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issues are focused on what we'll look at for the track two, with the fiscal issues that will come. So, all of these things, you know, we have to be partners in coordinating. For me, it's looking at what we do know, in terms of potential retirements, aging infrastructure, you know, pipeline constraints, and all -- all of those things sort of merged together and being able to work together.

And so, I just thank you for what I think was a very informative technical conference that helps set the stage for what we all have been doing and continue to do. And this is very important.

So, thank you Chair and thank you Staff and Panelists. And, you know, the rock star Wes, in the corner, there. So, thanks.

CHAIR ZIBELMAN: Let me just add -- just because now that I had a couple of minutes to think it.

I do think that this -- this issue about education is -- is one -- consumer education, we keep -- it seems to be coming back to it, is how do we get, you know, we talked about getting
consumers engaged in REV, but how do we get consumers
to -- to understand, because, unfortunately -- and I
think we've heard from this, is -- is that with
everything that goes on and everything we do, when
prices go up, the -- the expectation of consumers is
that somebody did something wrong.

And that's, you know, maybe --
and -- and I think we need to get people to
understand that there are tools available, but on the
other hand, we have to make sure those tools are
available and they're effective and they're
affordable.

So, I think that's a big piece
of -- of what we need to do going forward, is -- is
think about that. And certainly a big part of the
REV proceeding is how do we make that work better.

So and then I do think that the
work that ISO's doing is something we -- we
definitely want to support and -- and make sure we
understand how that can move -- help us help
consumers.

With that, one last point I wanted
to make, because I didn't want to forget it, you
might have noticed that Commissioner Sayre has not
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turned into Secretary Burgess, but he had another commitment today. He's at another hearing and -- since we couldn't manufacture two Commissioner Sayres. He desperately wanted to be here because this is a topic he's very interested in, but I'm sure he'll be reading the record and be following this very closely.

So, thank you all and thanks staff for arranging this and we look forward to your comments.

(The hearing concluded at 3:29 p.m.)
STATE OF NEW YORK
I, Kirsten Lemire, do hereby certify that the foregoing
was reported by me, in the cause, at the time and place,
as stated in the caption hereto, at Page 1 hereof; that
the foregoing typewritten transcription consisting of
pages 1 through 279, is a true record of all proceedings
had at the hearing.

IN WITNESS WHEREOF, I have hereunto
subscribed my name, this the 22nd day of May, 2014.

______________________________
Kirsten Lemire, Reporter