Before the

FEDERAL ENERGY REGULATORY COMMISSION

980th Open Commission Meeting

Thursday, April 18, 2012

Hearing room 2C

888 First Street, N.E.

Washington, D.C.

The Commission met, pursuant to notice, at 10:44 a.m., when were present:

COMMISSIONERS:

JON WELLINGHOFF, Chairman

PHILIP MOELLER, Commissioner

JOHN NORRIS, Commissioner

CHERYL A. LaFLEUR, Commissioner

FERC STAFF:

KIMBERLY D. BOSE, Secretary

MICHAEL BARDEE, General Counsel

JIM PEDERSON, Chief of Staff

DAVID MORENOFF, Office of the General Counsel

NORMAN BAY, OE

JEFF WRIGHT, OEP

MICHAEL McLAUGHLIN, OEP

JOSEPH McCLELLAND, OER

JAMIE SIMLER, OEPI

P R O C E E D I N G S

(10:44 a.m.)

CHAIRMAN WELLINGHOFF: This meeting will come to order. This is the time and place that has been noticed in the Sunshine Act for the Federal Energy Regulatory Commission to proceed.

So if we could all start with the Pledge of Allegiance, please.

(Pledge of Allegiance recited.)

CHAIRMAN WELLINGHOFF: Sorry we were a little late today, but we had to sort of wrap up a few items that we're working on some details of the language. So we will get started and see if we can move along. We've got a lot of important things to look at today.

One of the preliminary things that I need to do, first of all, since the January 19th Open Meeting we have issued 91 Notational Orders, which is quite an increase over last month when it was only 46. So we have kind of picked up the pace a little bit, which usually happens up through July, which is usually then our biggest meeting.

Before we go to the Consent Agenda, though, I would like to announce a change in my personal staff. Mike Henry is leaving the Commission after more than a decade of service. During that time, he was an attorney, and then a managing attorney in the Energy Markets section of the

Office of General Counsel. He also worked on detail within Commissioner Joe Kelleher, and most recently has spent more than a year as a Legal and Policy Advisor in my office. And his work and his presence is going to be missed.

His work responsibilities focused on New England matters, reliability, and generation interconnection, and he was known for his skill at bringing calm to the commotion of preparing for the public meeting, such as we had today, often with a well-placed poem. And so to try to be reciprocal, I am going to read a limerick for you here.

(Laughter.)

CHAIRMAN WELLINGHOFF: I once had an assistant named Mike who never met a challenge he didn't like. With his intellect, wit, and grace, Mike made FERC a better place. We wish you luck in your new job up the pike.

So with that, Mike has served with great distinction. We wish him well in his new endeavors, and I have the great pleasure to present him with the Chairman's Medal. Mike.

(Presentation made.)

(Applause and standing ovation.)

CHAIRMAN WELLINGHOFF: Congratulations. Thank you. Thank you, Mike. Thank you for your service to the Commission, Mike, we appreciate it very, very much.

I also want to mention that we--you know, it's not that you're irreplaceable, Mike; there always are replacements, and we found a great one. New to my office is Debbie-Anne Reese. Debbie-Anne has been with the Office of General Counsel Energy Markets for more than six years, working primarily on electric proceedings. She also has extensive experience in administrative and regulatory matters. Prior to law school, she worked for Verizon Communications. She earned her law degree at Georgetown University and graduated Magna Cum Laude in Finance from Howard University, and I am pleased to welcome Debbie-Anne to my team. Debbie-Anne.

(Applause.)

CHAIRMAN WELLINGHOFF: And I know, colleagues, that you have some comments on some of our Consent items, but we will do that after we vote on Consent. Does anybody have any general announcements they need to make?

(No response.)

CHAIRMAN WELLINGHOFF: Okay, good. So with that, Madam Secretary, if we could move to the Consent Agenda, please.

SECRETARY BOSE: Again I want to remind our audience to turn off any cellphones or electronic devices as they interfere with our microphones.

Good morning, Mr. Chairman. Good morning, Commissioners. Since the issuance of the Sunshine Act

Notice on April 12th, 2012, Items E-17, H-1, C-2, C-3, and C-6 have been struck from this morning's agenda. And your Consent Agenda is as follows:

Electric Items: E-1, E-2, E-3, E-4, E-5, E-6, E-7, E-8, E-9, E-10, E-11, E-12, E-13, and E-18.

Gas Items: G-1 and G-2.

Hydro Items: H-2 and H-3.

Certificate Item: C-1.

As to E-7, Commissioner Norris is concurring in part with a separate statement.

As to E-8, Commissioner Norris is dissenting in part and concurring in part with a separate statement.

As to E-9, Commissioner Norris is dissenting with a separate statement.

As to E-10, Commissioner LaFleur is dissenting with a separate statement.

We will now take a vote on this morning's Consent Agenda, and the vote begins with Commissioner LaFleur.

COMMISSIONER LaFLEUR: Thank you, Kimberly. Noting my dissent on E-10, I vote aye.

SECRETARY BOSE: Commissioner Norris.

COMMISSIONER NORRIS: Noting my separate statements on E-7, E-8, and E-9, I vote aye.

SECRETARY BOSE: Commissioner Moeller.

COMMISSIONER MOELLER: Votes aye.

SECRETARY BOSE: And Chairman Wellinghoff.

CHAIRMAN WELLINGHOFF: Vote aye. And then with respect to comments, I guess we ought to take these in numerical order. I understand, Commissioner Norris, you have a comment on E-3?

COMMISSIONER NORRIS: Yes. Thanks, Mr. Chairman. I just wanted to highlight it. I think the NOI that looks at our case-by-case policy on Open Access and the granting of Priority Rights to Capacity on certain interconnection facilities is--I'm looking forward to comments on this. I think they are excellent questions and we'll hopefully get some thoughtful comments. But I think it also addresses the broader issue of the application of the Commission's Open Access policies to some of industry's new challenges. The Open Access policy is 20 years old now, and I am not advocating changes in Open Access but I do think we have to look at some of the emerging issues with interconnecting some of our remotely located renewable resources, and how that meshes with the Open Access policy: How do we maintain the principles and the access to generation that we so greatly prize in terms of the competitive market? But to also make sure that we look at the challenges, unique challenges, facing some of the new challenges in industry in getting this remote energy to our transmission network.

So I look forward to comments on this. I think we are making a good step forward with this NOI, Mr. Chairman.

CHAIRMAN WELLINGHOFF: Thank you, John, and I agree with your comments. I think we do need to look at the changing landscape of the resource mix. It is important to be flexible and understand how our rules may need to change potentially to ensure that we can have all resources fairly and fully integrated into the markets. I think that is very, very important.

I have comments on E-12 and E-13, and I know we have some others. Does anybody have any comments on anything prior to E-12 and E-13?

COMMISSIONER MOELLER: Jon, I would like to comment on E-2.

CHAIRMAN WELLINGHOFF: Sure.

COMMISSIONER MOELLER: This is an Order that perhaps may not be the perfect resolution for all parties involved, but nevertheless it is important to get it moving. PJM asked for it quite awhile ago, almost two years ago. It is important to keep this issue moving forward, and therefore I am happy to support the Order.

CHAIRMAN WELLINGHOFF: Thanks, Phil. I agree with you on those comments, as well.

Anything else before E-12 and E-13?

(No response.)

CHAIRMAN WELLINGHOFF: Well on E-12 and E-13, I would like to address those briefly. They are related to the Coordinated Transaction Scheduling between New England ISO and the New York ISO.

I am very enthusiastic about what these two Orders represent. I have stated repeatedly that there are significant economic gains for consumers to be made by searching out and implementing improvements in operational efficiency. And that is just what the two ISOs here have done.

They have alternately worked together and studied how to improve their scheduling practices for transactions that cross the border between them. By coordinating the dispatch of generation between their markets, these ISOs can better meet demand at the lowest total production cost, which is not just a central ISO objective but is also an important objective of mine, and an important objective of our Strategic Plan.

In fact, the New York ISO's Market Monitoring Unit estimates that if the measures adopted in these Orders had been in place in 2008 to 2010, they would have reduced total production cost by approximately $30 million, and total energy expenditures load by approximately $400 million for the two regions combined. This is a tremendous amount of money, and going forward is going to be a tremendous reduction in cost. I think the Order estimated about $120-, $130 million per year potentially going forward.

So the improved coordination across the seams of these two regions will allow consumers to reap economic benefits of greater efficiency. So I would encourage other ISOs and RTOs to take note and consider how their systems can achieve greater efficiencies for their customers.

I also would encourage other areas of the country that do not have RTOs to note the money may be left on the table for foregoing the opportunity to also implement such operational efficiencies within their regions.

So with that, are there other comments on 12 and 13? John, or Phil?

COMMISSIONER MOELLER: I just want to associate my feelings toward your comments, and probably what Commissioner LaFleur says as well. These are two very good Orders and am happy to support them.

CHAIRMAN WELLINGHOFF: Cheryl?

COMMISSIONER LaFLEUR: Well thank you, Phil. I appreciate the vote in advance.

(Laughter.)

CHAIRMAN WELLINGHOFF: You can say whatever you want to now.

(Laughter.)

COMMISSIONER LaFLEUR: I just wanted to also just give a quick shout-out to the New York ISO and ISO New England. I think the Chairman has described the merits of the Order. I'll post a statement on my website, but this is something that came out of a white paper back in 2010 that is really the first of a few phases that they're going to be looking at in ways to improve the nuts and bolts of the way the operations work across the seams between ISO New England and New York with real benefits to customers--estimated between $129- and $139 million in annual benefits for customers in the two regions just from this coordinated scheduling.

They are going to be going on to look at energy exchange and congestion management across the seams and see benefits there, as well.

I think it is great that they have set it up so that the Market Monitor will be watching it, reporting back, and making sure it works as intended. And I commend them for going through the work to take this through two separate stakeholder processes in bringing it together. I think it is a great example of what we hope to see along the seams between ISOs and between markets across the country.

Finally, I just want to thank the FERC teams that worked on the Orders. Thank you.

CHAIRMAN WELLINGHOFF: Thank you, Cheryl. Madam Secretary, I think we are ready to go on to the Discussion

Agenda.

SECRETARY BOSE: The presentation and discussion item for this morning is A-3, and that is concerning the Office of Enforcement's 2011 State of the Markets Report. There will be a presentation by Valeria Annibali and Lance Hinrichs from the Office of Enforcement. They are accompanied by Steve Michals and Chris Ellsworth, also from the Office of Enforcement. There will be a Power Point presentation on this item.

(Slide.)

MS. ANNIBALI: Good morning, Mr. Chairman, and Commissioners:

We are pleased to present the Office of Enforcement's 2011 State of the Markets Report. The State of the Markets Report is our opportunity to share our assessment on the natural gas, electric, and other energy markets. This presentation is based on conclusions of the staff and not necessarily of those of the Commission, the Chairman, or any of the individual Commissioners.

(Slide.)

Natural gas production reached an all-time record in 2011, surpassing levels last seen in the 1970s. Growing supply outpaced demand, which led to record high levels of natural gas storage going into the 2011/2012 winter, and natural gas prices fell to lows not seen since the early

2000s.

Plentiful natural gas supply and low natural gas prices led to talk of a need to develop new markets for natural gas, and in 2011 seven LNG export projects were proposed in the U.S. with almost 14 Bcf a day of capacity.

The electric markets also experienced low prices as fuel costs fell and demand remained stable. Changes in the pricing relationship between natural gas and coal-fired generators caused a fundamental shift in the utilization of these plants, with natural gas plant production increasing and coal plant output falling.

(Slide.)

In this slide, we compare the current Henry Hub natural gas spot price to the 10-year range shown in green to illustrate how prices fell below that range towards the end of 2011.

In 2011, natural gas prices at Henry Hub were down about 9 percent from 2010. The price of natural gas fell from the mid-$4/MMBtu range at the beginning of the year to under $3 by December. The price remained at the $3 level through the end of the year and reached parity with Central Appalachian coal.

The most recent Nymex forward curve for natural gas shows that market anticipates that prices at Henry Hub will remain under $4 through 2014. Some natural gas producers have voiced concerns that declining revenues due to low natural gas prices will affect their ability to explore for and produce natural gas.

We have already seen some producers announce plans to cut back natural gas production in gas-only shales while increasing drilling in shales rich in natural gas liquids. These announcements and possible impacts on production are trends we will watch closely in 2012.

(Slide.)

Average natural gas spot prices declined across the country in 2011 by around 7 percent, as shown on the map. This winter was the warmest in 60 years and the Northeast, which usually sees the highest winter prices, saw no sustained peaks.

The Transco Zone 6 New York price for this winter averaged only $4.25/MMBtu with a peak at only $12, whereas last winter prices averaged nearly $7 and peaked in December at $20.

New pipelines completed during 2011 linked growing supply sources to markets and contributed to shrinking regional price differences. In some cases, the market price of natural gas between regions declined to less than the variable transportation costs, making it uneconomical to move natural gas to try to capture the price differences between pricing points.

We have also seen a decline in the seasonal difference between winter and summer natural gas prices. Falling seasonal spreads reflect increased production and storage capacity, as well as greater year-round use of natural gas by power generators. This decline has developed over the past several years and we expect the trend to continue.

(Slide.)

The recent warm winter, relatively low natural gas demand, and strong production exacerbated the current oversupply situation in the market. By the end of March, natural gas in storage was over 50 percent higher than the 5-year average which is shown in green on the graph.

Natural gas in storage has never been at such high levels going into the spring, and this will help inventories rebuild for next winter.

Although very high storage levels so early in the refill season indicate a need for additional storage, market conditions do not generally support the building of new storage capacity. Also, as mentioned in the previous slide, winter-summer gas price spreads are at historically low levels and barely cover the cost of storing gas.

(Slide.)

This slide shows natural gas production over the last seven years by source. Dry natural gas production grew

7 percent in 2011 to 65 Bcf a day, surpassing an all-time record last set 25 years ago.

Growth was primarily driven by robust on-shore shale gas production, which accounted for a third of total U.S. gas production by December 2011. This is up from 23 percent in 2010, and just 13 percent three years ago.

Dry gas shales in the Gulf Coast remained the largest producing shales in 2011. However, the fastest growing shales were found in the liquids-rich shale basins.

The Marcellus Shale, which is a liquids-rich shale in parts of Pennsylvania and West Virginia, have production doubled over the last year to nearly 6 Bcf a day.

Production from the Eagle Ford Shale in South Texas grew 64 percent to 3 Bcf a day, which is the highest growth of any shale basin. Some Eagle Ford wells produce as much as 70 percent liquids which can double profitability compared to a gas-only well.

This rapid increase in natural gas liquids production outstripped liquids processing and takeaway capacity in many regions, resulting in development and production bottlenecks.

The liquids infrastructure in the Appalachian region was not designed to handle the volumes produced by the Marcellus Shale. The Eagle Ford Shale region also faces similar problems. Industry plans to add over 700,000 barrels of fractionation and processing capacity and 1.3 million barrels per day of liquids pipeline takeaway capacity by 2014 to alleviate some of these bottlenecks.

Low prices and the drive to tap shale gas reserves have touched off a race to reduce drilling [costs] and improve rig operating efficiency. These improvements resulted in production increases even as the gas directed rigs declined.

In 2011, the natural gas directed rig count dropped 6 percent while production continued to increase. There are many shale gas wells that have been drilled but not completed because producers are waiting for higher prices. This will enable gas production to come on-line quickly as market conditions warrant.

Concerns about environmental issues associated with hydraulic fracturing remained at the forefront in 2011. The Environmental Protection Agency continues to study the relationship between hydraulic fracturing and drinking water with its final study plan released in November 2011, and the final results not expected until 2014.

At the state level, actions on fracking range from outright bans such as the one in the New York City watershed, to the reassessment of current regulations in the Utica Shale as the [Ohio] State prepares for oil and natural gas development.

There have been some reports of increased flaring levels, as well, of gas associated with the increase of oil production, but these are mostly a localized phenomenon. The overall level of flaring in the U.S. in 2010 remained less than one percent of dry gas production, essentially unchanged from the average amount flared for the last 30 years.

(Slide.)

U.S. natural gas consumption in 2011 was up less than 1 percent from 2010. As shown, most of the growth came from natural gas-fired power generation, which was up slightly more than 3 percent. There was virtually no change in industrial natural gas consumption, and residential and commercial use fell 0.7 percent.

While overall natural gas consumption varies by year, strong growth in natural gas-fired power generation supported 10 percent growth in consumption over the last 10 years as Lance will discuss later in the presentation.

The greater reliance on natural gas has increased the importance of coordination between gas-fired generators and natural gas pipeline companies that supply them. Concerns about coordination have been especially strong in the heavily gas-dependent Northeast, which has experienced coincident peaks in both electric and natural gas demand during the peak winter seasons.

It can also be a concern in parts of the Southwest that lack sufficient storage infrastructure. Also, upcoming coal plant retirements--outages for emission retrofits are expected to lead to greater use of natural gas-fired plants. Regional grid operators continue efforts in areas of planning, reliability, and market operations.

Over the past year, as focus has increased on gas-electric coordination, natural gas and electric companies have launched initiatives such as the enhanced communications between the various industry segments, including generators, RTOs, and pipeline companies.

In February 2012, the Commission issued administrative docket AD12-12 requesting comments on the issue of natural gas and electricity interdependence. Approximately 80 interested entities submitted comments, and Commission staff is currently reviewing their submissions.

(Slide.)

Last year transportation capacity values dropped on many long-haul pipelines as strong production growth in the Marcellus and other shale basins displaced some natural gas flows from traditional sources.

For example, we saw Rockies flows to the Northeast and Rockies Express Pipeline decline more than 40 percent since early November 2010 from 1.7 Bcf a day to

1 Bcf a day. The decline was so severe that S&P reduced REX's credit rating. This downgrade is the result of persistent low profitability in shipping Rockies natural gas eastward. This has resulted from Rockies natural gas being displaced in the Northeast by increased flows of less-expensive Marcellus Shale gas.

Also, the new ruby pipeline competed with REX, providing Rockies producers access to a more profitable market in Northern California. S&P said that lower profitability now has increased the recontracting risk on REX as well. As with the Rockies, traditional Gulf Coast supplies have also been displaced by largely liquids-rich Mid-Continent production.

In 2011, FERC jurisdictional natural gas pipeline companies added roughly 2,100 miles of new pipe and about 9 Bcf a day of transportation capacity, while major intra-state pipelines added another 400 miles of new pipe and about 4.7 Bcf a day of transportation capacity.

The six largest projects, shown on the map, account for 57 percent of new transportation capacity. Some of the major projects included Ruby Pipeline, Florida Gas Transmission Phase VIII Expansion, and the Bison Pipeline.

In 2011, pipeline developments shifted to projects focused on relieving local bottlenecks in new production basins rather than long-haul pipelines. Most of these occurred in the Northeast and the Southeast, and included the Tennessee Gas pipeline Line 300 Expansion, the Texas Eastern TEMAX/TIME III project, and the Acadian Haynesville Extension, which is an intrastate pipeline that feeds into the Henry Hub.

(Slide.)

FERC Order No. 720, issued in October 2010, required major noninterstate pipelines to post daily nominated receipts and deliveries on their systems--the blue area on the graph. This resulted in a sharp increase in market transparency during 2011, with 97 percent of daily dry natural gas production visible to the market through pipeline receipts.

Order No. 720 data made visible to the market daily natural gas production from some of the fastest growing shale plays. Demand visibility also increased significantly with implementation of the Order. Prior to Order No. 720, the market did not have thorough information on the intrastate market customer mix. For example, the amount of daily natural gas consumption from industrials or power generators in markets served predominantly by intrastates was not visible.

The Order No. 720 postings also allowed the market to see the impact of daily changes in natural gas supply and demand and their effects on the interstate price formation and fundamental market dynamics. For example, in February 2011, Order No. 720 postings enabled market participants to quickly assess the regional extent and impact of natural gas well freeze-offs as shown in the graph by the sharp dip in intrastate pipeline flows during February 2011.

In 2011, the Fifth Circuit Court of Appeals vacated the Order and most nonintrastate pipeline postings ceased at the beginning of 2012. Now the market is only able to observe about 70 percent of daily changes in dry natural gas production and even less demand.

Recently, many producers announced a dial-back of natural gas production in response to low natural gas prices. With the loss of Order No. 720 data and with it producer deliveries into intrastate pipelines, it has become more difficult for market analysts to assess whether announced well shut-ins are actually occurring and, if so, what effect they are having on market dynamics. Less information usually injects greater uncertainty, price volatility, and risk into the market.

(Slide.)

U.S. producers are seeking new foreign markets for growing supply and nearly 14 Bcf a day of export capacity was proposed in 2011 at various locations shown on the map. To put this into perspective, 14 Bcf a day would have been about 21 percent of 2011 average daily U.S. natural gas production.

EIA recently completed an assessment of the domestic price impact of U.S. LNG exports and concluded that U.S. natural gas prices could rise 9 percent at 6 Bcf a day level and 11 percent at the 12 Bcf a day level.

A number of other studies have also analyzed various U.S. LNG export levels with some showing no appreciable effect on prices, and others showing a greater impact than the EIA.

Cheniere Energy's Sabine Pass LNG, which has been approved by the Department of Energy to export domestically produced gas as LNG, is the furthest along with 90 percent of its proposed export capacity contracted by buyers from Korea, India, and Spain.

These buyers are likely willing to pay a price premium for the security and diversity that the U.S. natural gas market provides. So far, the Lower 48 has only re-exported small quantities of previously imported LNG. In its 2012 Annual Energy Outlook forecast, the EIUA projects that U.S. LNG exports will begin in 2016 at 1.1 Bcf a day, doubling to 2.2 Bcf a day by 2019.

I will now turn my--the presentation over to Lance HInrichs to discuss developments in the energy markets.

(Slide.)

MR. HINRICHS: Thanks. Power Prices in 2011 were down throughout the U.S., with the exception of the ERCOT RTO and the Cinergy Trading Hub. This largely tracked the drop in natural gas prices that Valeria described and highlights the role of natural gas as the marginal, or price setting, fuel in most markets.

On average, nationwide power prices were down one-half percent from last year, despite a warmer than normal summer.

Prices in the East were between 3 percent and 12 percent lower, primarily due to the lower natural gas prices. Western power prices fell between 7 and 19 percent supported by the robust hydroelectric output in the Northwest that was 27 percent above the 5-year average.

The most dramatic change occurred in ERCOT where prices rose by 40 percent due to excessive summertime heat that set a record-breaking 41 straight days at or above 100 degrees.

As a result, in August there were 9 days in which ERCOT's energy-only market saw day-ahead prices rise to the $3,000-per-megawatt-hour price cap. This was in contrast to the Southwest Power Pool region which also experienced a hot summer. However, prices in the SPP fell by 6 percent, primarily due to a robust capacity surplus and power imports of 2 to 3 gigawatts during peak periods.

(Slide.)

Natural gas-fired combined cycle generation--shown in red on the chart--continues to move up in the Nation's supply stack, displacing coal-fired generation--shown in green. Coal generation as a percentage of total output declined steadily to 44 percent in 2011 from about 51 percent in 2002. Over the same period, generation from natural gas-fired combined cycle plants grew to more than 20 percent, up from 10.

The underlying reasons for increased natural gas generation use are well known. These plants are cheaper to build, have shorter construction timelines, offer more flexible operations, and have fewer environmental restrictions.

Coal plant construction, however, has not come to a halt. Coal still maintains a fuel-cost advantage for large base-load plants in certain locations, particularly where delivered coal costs are low.

This brings us to a more recent situation where decreases in natural gas prices are causing natural gas combined cycle plants to replace some coal plants in the generation stack. Some of this transition was starting to take place when natural gas prices are $1 to $1.50 higher than they are today.

However, there is now additional pressure for natural gas-fired plants to compete with coal production. Low natural gas prices in 2011 helped push the proportion of coal generation down during the year, ending at 39 percent of total U.S. generation in December.

Over roughly the last decade, the largest volume of natural gas-fired combined cycle generation construction occurred during the 2000 to 2005 period. Their capacity factors have been growing steadily since that time, from the low 30 percent range to nearly 40 percent now.

(Slide.)

In last year's State of the Markets Report we told you that the consumption of electricity had partially recovered from a recession-induced decline in 2009. In 2011, this rebound appeared static and overall demand was down by 1 percent with little change in each of the three major consumer categories.

This chart shows industrial demand, which was up last year by less than 1 percent from 2010 levels, and mirrors economic activity which rose at a moderate pace, according to the Federal Reserve.

Commercial sales, which are driven by a combination of weather and economic activity, also rose slightly in 2011 from the year before.

Residential sector consumption, which is primarily driven by weather, fell 1.5 percent in 2011 despite record peak loads in many areas of the country during the summer. Last year's dip in residential electricity sales runs counter to a longer term trend towards more energy-efficient technologies in homes and larger residential structures.

(Slide.)

The 218-mile 500 kV TrAIL power line in PJM went into service in May 2011. The line begins in southwestern Pennsylvania, crosses northern West Virginia, and terminates in Loudon County, Virginia. It increases west-to-east transfer capability by over 2,600 megawatts and has helped reduce congestion, bringing prices in eastern and western PJM closer together.

The graph shows the drop in the price difference between the Dominion Hub and the AEP-Dayton Hub, falling from $14.67 per megawatt hour in the summer of 2010 to $6,68 per megawatt hour in the summer of 2011.

Over the two interfaces that benefit from the TrAIL, congestion declined sharply and allowed lower cost generation in western PJM to flow to eastern and southern PJM. On the AP South interface, congestion declined by 1,000 hours while congestion on the Bedington-Black Oak interface declined by over 1,800 hours. Total congestion costs over these two interfaces dropped by half to $262 million in 2011.

TrAIL's benefits were also evident in PJM's forward capacity market. The Reliability Pricing Model, or RPM, provides load serving entities a means of procuring capacity three years in advance of the actual delivery year. This was first seen in the May of 2008 auction for the 2011/2012 delivery year, when the line's projected capacity was included in the auction's assumptions for those delivery years.

As a result of the line's increased deliverability of capacity, the difference in capacity prices between the east and west regions dropped to zero for the 2011/2012 delivery year from more than $100 per megawatt day for the 2009/2010 period.

TrAIL has also enhanced system reliability and operational flexibility by making it possible for the RTO to accelerate the reconstruction of the 100-mile long Mt. Storm-Doubs 500 kV line which runs on a roughly parallel path to the TrAIL. TrAIL's new capacity allows operators to take longer outages on the Mt. Storm-Doubs line during construction and will make it possible to have the line rebuilt by June 2015, about 5 years earlier than would otherwise have happened.

(Slide.)

Demand response participation in the RTOs has been increasing and grew by 40 percent last year in the Northeast to 20 gigawatts of cleared capacity.

In 2011, two notable events demonstrated the important role that demand response plays as capacity that resource operators can call upon to more flexibly balance supply and demand.

On July 22nd, a heat wave hit the Northeast and Mid-Atlantic, sending temperatures soaring to 104 degrees in New York Ci9ty, and pushing electricity demand to near-record levels. In the most stressed markets--New York ISO, PJM, and ISO-New England--grid operators invoked emergency measures and called upon real-time demand response programs that activated 4,800 megawatts of demand response.

Also, on December 19th, ISO-New England experienced a deficiency in operating reserves during the morning ramp and activated 500 megawatts of demand response. The deficiency was caused by a combination of factors: forced outages, higher than expected load, and unit trips.

During both the July and December events, the programs helped to maintain system reliability and provided operators with alternatives to the most expensive generating units or curtailing service to customers.

Demand response continued to account for substantial capacity in the RTO capacity market auctions held in 2011. In the PJM and ISO-New England forward capacity auctions, which were held for the 2014-2015 delivery period, demand response resources represented 10 percent of the capacity cleared for PJM and 8 percent for ISO-New England. In the New York ISO where its capacity auction was held for the 2011 Summer Capability Period, demand response represented 6 percent of the cleared statewide capacity.

Providing upwards of 95 percent of their compensation in PJM and New England, and more than 50 percent in New York, the capacity markets provided the demand response resources participating in these grid events with significant incentive to enter the market.

In the forward capacity market auctions held in 2011, the PJM and ISO-New England capacity market payments represented between 37 and 60 percent of the net cost of new generation in the regions. In New York, the ISO-provided capacity payments represented approximately 58 percent of the cost of new generation in New York City.

(Slide.)

With the Treasury Department's cash-grant program expiring and costs falling, developers rushed to connect photovoltaic solar capacity to the grid last year. There was 1.9 gigawatts of new capacity, or a 109 percent increase from 2010 installed, led by California and New Jersey.

At year-end, total capacity reached approximately

4 gigawatts. In each of the top states, solar investment was encouraged through policies such as solar set-asides and renewable standards. Additionally, photovoltaic construction costs fell 20 percent last year, following an 18 percent drop that occurred in 2010.

U.S. wind generation capacity grew by 6.8 gigawatts last year. More than a third of this increase came online in the Midwest ISO and SPP. With capacity factors between 30 and 37 percent, now 1 of every 11 megawatt hours in these regions comes from wind.

As wind generators provide an increasing portion of the market's energy, they need new tools to manage its output more efficiently. On june 1st, MISO instituted a voluntary tariff category for variable energy resources--principally, wind.

By allowing registered resources to be dispatched economically in real time, "DIR" provides more efficient curtailment through market software to manage congestion, a common need in Minnesota and Iowa and other parts of MISO's western region.

Previously, wind resources might be manually curtailed as often as three times a day with the system instructing generators to turn off large blocks of production for long periods of time. By December, 19 percent of MISO's 10.6 gigawatts of wind had registered as

DIR resources.

Hydro generation in the Pacific Northwest finished 27 percent higher in 2011 than the 5-year average, with roughly 160 terawatt hours generated in 2011. California hydro generation hit roughly 40 terawatt hours, 60 percent more than the previous 5-year average.

As a result, hydroelectric generation displaced natural gas generation in much of the West. For example, California burned 23 percent less natural gas in their power plants than the 5-year average, while Washington State burned 43 percent less.

This completes our presentation. We would be happy to answer any questions at this time.

CHAIRMAN WELLINGHOFF: Thank you both for your presentations, and I want to thank the entire team for a great effort here and a very, very comprehensive and well-done report. Thank you, very much.

Colleagues, any questions, comments? Phil?

COMMISSIONER MOELLER: Thank you, Chairman. I will echo the thanks for an excellent presentation and the work of the team. It was very comprehensive and yet relatively concise, given the volume of information you had.

First on the gas side, I want to thank the 80 parties that submitted comments on our gas/electric questions. I am reviewing them and I look forward to our next steps in that effort.

As you noted, we are seeing a supply of gas domestically with low prices. That's good for consumers and, frankly, good for regulators, but not necessarily good for producers. And the concerns we hear about are increased dependence on gas, particularly, for electricity are related to the boom and bust cycles of gas and how the prices of course can be volatile.

And one of the reasons we've had a lot of gas, as I understand it from the people I've talked to, who are more downstream, is that leases often required people to drill in a certain amount of time, within a five-year window. And I am wondering if you can elaborate on the extent to which that is occurring and perhaps evolving? And as you watch this set of issues over the next year, your thoughts on the details of leases driving perhaps some overproduction in the last couple of years.

MS. ANNIBALI: Thank you for your question. Yes, we have seen that the period of leases does incentivize the pace of drilling. For example, in Marcellus Shale the leases tend to be five years; as well as in the Utica Shale in Ohio.

If you go down to the South Texas area, the Eagle Ford Shale, they're about three years. But I think the main driver for the faster drilling pace that continues the incentives in addition to lease times is the value gained from gas being associated with NGLs and oil. So we see that as a larger driver behind it, as well.

COMMISSIONER MOELLER: All right. To what extent do you see--you mentioned wells being shut in, but how significant is that trend? And, given the visibility of the information that we have and the limited visibility of intrastate, what's your sense as to the extent of shut-in wells?

MS. ANNIBALI: Currently we haven't actually seen a lot of production decreases, one, because of, instead of just having natural gas produced from dry-gas wells, I think what has happened is a shift to oil-directed reg count and production, associated production from that. So overall, some dry gas only wells might be shut in. The increased production from gas associated with NGLs and oil continues to grow. So it has balanced that out. So we haven't seen overall effects of decline in production.

COMMISSIONER MOELLER: Okay. You highlighted this, but just to reiterate it, the soonest we could see significant export of LNG would be in the range which years?

MS. ANNIBALI: 2016 to '18, depending on the construction timeline of the projects and any complication or delays.

COMMISSIONER MOELLER: So presumably we would not see price--assuming there are price increases, and that's an assumption--from exports, we wouldn't see them until that time?

MS. ANNIBALI: Correct. Unless there's an increase in--a surge in domestic demand.

COMMISSIONER MOELLER: Sure. Certainly. Okay.

Well implied in your presentation but not really specifically pointed out was the fact that we've been able to absorb this incredible domestic supply, I think partly because this Commission and the leadership of Jeff Wright and his team have been able to certificate storage and pipelines in a timely manner that has allowed us to absorb that incredible domestic resource. And kudos to Jeff and his team for that.

Finally on electricity, thank you for pointing out the benefits of the TrAIL line, a very significant investment. Do you have, Lance, a sense of the payback time involved, given the big numbers of savings in congestion costs involved?

MR. HINRICHS: Well we haven't done the numbers on that. The primary--the primary benefit and purpose of putting that line into place was reliability based. But, Steve, did you have any other comments on that?

MR. MICHALS: Additionally, yes, with the reliability focus that was largely behind the decision to go forward with TrAIL, it's providing PJM the ability to accelerate the construction on the parallel path of Mt. Storm-Doubs, and that too will provide additional reliability, as well as congestion benefits when that goes into service.

COMMISSIONER MOELLER: Well when we do the numbers, I'm guessing that it will be a very quick payback for a very significant project. I think it highlights the fact that these major transmission lines, although very difficult and sometimes expensive, are still a very good value for consumers. And I am hoping that that Susquehanna-Roseland Line, which similarly has a couple hundred million dollars per year of benefits to New Jersey ratepayers can go into service sooner rather than later so that they can, too, enjoy the benefits of increased reliability and lower congestion costs.

With that, Mr. Chairman, thank you.

CHAIRMAN WELLINGHOFF: Thank you, Phil. Cheryl.

COMMISSIONER LaFLEUR: Thank you. I just had one question. I thought that was terrific. Thank you for all the great information.

Most of what you talked about what on balance a pretty happy story. Gas price is down. Markets working better. Renewable construction up. And so forth. What do you see as the biggest threats, or challenges that the gas or electric markets will be facing in the next year or so? What should we be worried about?

MR. ELLSWORTH: I'll go ahead and answer that. I think one of the biggest threats we see in the gas market--I'll let Lance do the electric markets--but within the gas markets one of the biggest threats we see is these low gas prices, and the potential impact on production, and what Commissioner Moeller was talking about, the boom/bust, that it could go bust with the low gas prices.

We have seen a reduction in the gas-directed rig count. That could affect drilling crews and so on and so forth, and it could lead to that kind of bust in drilling that sets up the market then again for higher prices down the road. But we think such a phenomenon would be fairly short-lived simply because of the huge size of the shale gas resource.

Another issue that we have is the increase which Valeria touched on in the presentation, the increased use of gas for power generation and its impact on pipelines. We will see how that develops, but some pipelines, particularly during winter peaking seasons, are getting quite full, quite heavily utilized.

And then a third one that we're looking at is the recontracting risk on some long-haul pipelines. As they lose customers to shorter haul pipelines to take advantage of the Marcellus and other local production, there's a recontracting risk for portions of the long-haul pipelines that could impact the remaining customers on there if they decide they have to come in for a tariff adjustment because of lower revenue retrieval.

MR. HINRICHS: I would say that the power markets performed very well over the last couple of summers, which were very--experienced extreme weather. Probably the biggest impact that we are concerned about would be the low gas prices are creating a strong incentive for concentrating solely on that fuel, and losing some of the diversity that we have in our generation fleet, which is a real benefit of this system that we have. So it is a challenging part of a very good story.

MR. MICHALS: And I would just echo what Chris and others have said with regard to greater reliance on natural gas for electricity. Other offices, as well as Office of Enforcement, are watching the developments in greater coordination for gas and electric systems.

COMMISSIONER LaFLEUR: Well thank you. That was very helpful. One of the challenges I think we have when we look at so many micro issues in our Orders is seeing kind of the big mosaic of the big picture. And presentations like this are helpful to see that we're looking at the trends. I also worry about fuel diversity, because I've often said a lot of the diversity we have now is generational. We are kind of living off decisions that were made decades ago, and it's something we need to think about in both the gas and electric markets.

Thank you.

CHAIRMAN WELLINGHOFF: John.

COMMISSIONER NORRIS: I'll just pick up where Cheryl left off. Again, since I've been at the Commission, each year is great news on gas. And it is great news. But pardon me if I'm still nervous about over-reliance on one fuel source. We just need to keep our eye on it.

But, a great amount of data. I appreciate all the work that went into preparing this. A couple of questions on the gas side:

As we begin to, of course this week with the Cheniere Order, begin to look at exports, what's happening around the world in terms of--a lot of this gas is a result of technological developments and the ability to access it. Are there changing circumstances around the world in terms of access to shale gas that will have an impact on our export demand?

MS. ANNIBALI: Well overall there has been only limited studies looking at levels of U.S. LNG exports and how that would interact on the international markets. Overall, there has been increased talk of shale gas developments around the world in at least 30 countries. However, there are some issues and they haven't had the ability to reach the sustained level of production from shale gas as we have been able to here domestically.

There's some talk of shale developments in Europe and, you know, like in the UK and Poland, however European countries have a much more dense population where they're looking to develop their shale reserves. So that poses a problem.

Also, some developments are being talked about in China, for example, Asia, and--however, there's a lack of technological ability to develop the shales for a sustained period of time, as well. And recently actually they have cut down in half their reserve estimates from shale production based on several test wells they have been able to drill.

So while in the timeline for when the U.S. LNG export projects are stated to come on service, there could potentially be a risk if these countries do catch up on that technological gap and are able to produce shale gas.

COMMISSIONER NORRIS: Also there was a generalization in the report about storage, and that, you know, we obviously have high levels of left-over gas stored from last winter, and storage. But storage is going to be critical going forward. But I think the generalization was that the market conditions don't support the building of new storage.

Does that apply everywhere? Or are there regional differences such as we did in the Southwest this past year, and the study or the conference there on storage? And is that a unique circumstances?

MS. ANNIBALI: Okay. As far as storage value has significantly declined over the past couple of years, especially from a value that storage operators receive from intrinsic value in capturing seasonal price spreads. They are trying to add additional services to capture a small of services--a small value of services from Hub services.

However, overall for a--storage value has declined because of the prices, because of the seasonal spread especially that we've seen this winter, and that's particularly affected the merchant storage such as the salt cavern storage from primarily the Gulf Coast.

As far as other storage, it has impacted it but to a lesser degree.

Chris, do you have anything to add?

MR. ELLSWORTH: Going to your question about the Southwest, we are aware that one of the recommendations was for storage to be added in the Southwest to increase reliability. But we haven't seen any activity with that marketplace to actually add storage yet. I don't know whether you have anything, Jeff?

COMMISSIONER NORRIS: Is that mainly from market conditions, or is there something else holding us back?

MR. WRIGHT: Well the market conditions result primarily from the physical conditions out there. There's not a lot of geological formations that allow storage to be developed in the Southwest. And those that do lend themselves to that kind of development, you would have to solution-mine. You would have to bring the brine out from the salt deposits.

Therefore, you create another situation where you either have to pipe the brine away and reinject it in other wells, or you create evaporative ponds which have some environmental harm there with them.

In addition to that, we've seen state regulation that has actually been contra to storage development. One example is in Arizona. There was a site west of Phoenix, near an Air Force Base, and the State Legislature passed a law against developing that site for storage. So the potential developer decided not to go against the State and come to us.

So in the end, what that does develop is the market isn't interested in it because the development costs would be so great as to not be a real good opportunity. And for the open seasons that we've seen, they're not attracting a whole lot of people, so you're not going to really build storage on spec unless you get some firm contracts.

COMMISSIONER NORRIS: Thanks.

CHAIRMAN WELLINGHOFF: I want to thank the Office of Enforcement for this State of the Markets Report. If there is nothing else, this meeting is adjourned.

(Whereupon at 11:44 a.m., Thursday, April 18, 2012, the 980th Commission meeting was adjourned.)