1 Before the
2 FEDERAL ENERGY REGULATORY COMMISSION
3 969th Open Comission Meeting
4 Thursday, April 21, 2011
5 Hearing room 2C
6 888 First Street, N.E.
7 Washington, D.C.
8 The Commission met, pursuant to notice, at 10:03
9 a.m., when were present:
10 COMMISSIONERS:
11 JON WELLINGHOFF, Chairman
12 MARC SPITZER, Commissioner
13 PHILIP MOELLER, Commissioner
14 JOHN NORRIS, Commissioner
15 CHERYL A. LaFLEUR, Commissioner
16 FERC STAFF:
17 KIMBERLY BOSE, Secretary
18 MIKE BARDEE, OGC
19 DAVID MORENOFF, OGC
20 JAMES PEDERSON, Chief of Staff
21 JEFF WRIGHT, OEP
22 MICHAEL McLAUGHLIN, OEMR
23 JOSEPH McCLELLAND, OER
24 JAMIE SIMLER, OEPI
25 NORMAN BAY

1 P R O C E E D I N G S

2 10:00 a.m.

3 CHAIRMAN WELLINGHOFF:: This is the time and
4 place that has been noticed for the open meeting on the
5 Federal Energy Regulatory Commission to consider the matters
6 that have been duly posted in accordance with the Government
7 in Sunshine Act. Please join me for the Pledge of
8 Allegiance.

9 (PLEDGE OF ALLEGIANCE.)

10 CHAIRMAN WELLINGHOFF:: Well, since our March
11 17th open meeting, we've issued 93 notational orders. I
12 want to note that's up from 64, the month before, so we're,
13 I guess, working harder or doing something with respect to
14 notational orders.

15 Before we move to the Consent Agenda, I know
16 Commissioner LaFleur has something to say. So Commissioner
17 LaFleur.

18 COMMISSIONER LaFLEUR: Thank you very much, Mr.
19 Chairman. I just wanted to report that I returned last
20 night from representing FERC at the ten year foundation
21 meetings in Beijing. This is a broader federal initiative,
22 that was started by President Bush and continued by
23 President Obama. This was the third annual meeting, the
24 second one that has been in China, under the auspices of the
25 State Department.

1 What it is is a broad structure for cooperation
2 and sharing best practices on a range of topics related to
3 the environment and energy, of which one is electricity. So
4 our alternate member, our counterpart is the National
5 Electricity Administration, where I know John has spent a
6 lot of time with them on some of these topics.
7 It was a very, very educational trip. But I was
8 really struck by the common issues that we face on
9 integrating renewables. China has a huge amount of wind,
10 hydro, up north in the north part of the country, some of
11 which isn't even really connected to the grid yet.
12 Obviously then building transmission and how you're going to
13 organize the transmission grid becomes a big factor.
14 They're doing 1,000 kV lines, which was something
15 new to me, and a lot of work going on in the Smart Grid and
16 electric vehicles. So a great foundation for working
17 together in the future on those topics. I appreciate the
18 Chairman giving me the opportunity, and I look forward,
19 think there's an opportunity to learn from each other.
20 Thank you.
21 CHAIRMAN WELLINGHOFF:: Thank you, Cheryl, and I
22 appreciate you =very much representing the Commission on
23 that trip, and I know you were negotiating an MOU with them
24 that we're looking to hopefully sign this next month, and I
25 just want to emphasize how important this is, and I have a

1 few statistics here that I think are pretty astounding.
2 The Smart Grid market in China, the value will
3 grow from currently at 22.3 billion to by 2015, that's not
4 that many years away, 61 billion in value in Smart Grid.
5 China's emerging as the important test bed for electric
6 vehicles, as many of you know, and this is another
7 astounding figure. China apparently could have an installed
8 basis Smart meters that could reach a quarter of a billion
9 by 2020.
10 So you know, we're looking at a partner here that
11 certainly is moving extremely rapidly. We have a lot to
12 learn from them and I think they have a lot to learn from
13 us. I learned that Honeywell will develop and implement
14 China's first demand response pilot this next year.
15 So we're, I think, way ahead in that area, in
16 demand response. But certainly on the transmission side, as
17 Cheryl indicated, they have 1,000 kVA DC lines and have
18 inaugurated some substantial investments in transmission and
19 transmission upgrades, and I think we can learn from them.
20 So I'm looking forward to working with the
21 Chinese government and their utility sector as well, to see
22 how we can both work together to figure out some of these
23 problems. Thank you, Cheryl. I think if anybody else has
24 anything, we're ready to go to this Consent Agenda. Madam
25 Secretary.

1 SECRETARY BOSE: Good morning, Mr. Chairman and
2 good morning, Commissioners. Since the issuance of the
3 Sunshine Act notice on April 14th, 2011, no items have been
4 struck from this morning's meeting. Your consent agenda for
5 this morning is as follows:
6 Electric items. E-5, E-6, E-7, E-8, E-9, E-10,
7 E-11, E-12, E-14, E-15, E-16, E-18, E-19, E-23 and E-24.
8 Gas items. G-1, G-2, G-3 and G-4.
9 Hydro items. H-1, H-2 and H-3.
10 Certificate items. C-1, C-2 and C-3.
11 As required by law, Commissioner Spitzer is not
12 participating in consent item E-18. We will now take a vote
13 on this morning's consent agenda. The vote begins with
14 Commissioner LaFleur.
15 COMMISSIONER LaFLEUR: Thank you. I vote aye.
16 SECRETARY BOSE: Commissioner Norris.
17 COMMISSIONER NORRIS: Aye.
18 SECRETARY BOSE: Commissioner Moeller.
19 COMMISSIONER MOELLER: Votes aye.
20 SECRETARY BOSE: Commissioner Spitzer.
21 COMMISSIONER SPITZER: Votes aye. Noted my
22 recusal in Item E-18.
23 SECRETARY BOSE: And Chairman Wellinghoff.
24 CHAIRMAN WELLINGHOFF:: I vote aye. With that,
25 if we could then move to the discussion agenda, please.

1 SECRETARY BOSE: We'll have a presentation this
2 morning from the Office of Enforcement, on Item A-3,
3 concerning the 2010 State of the Markets report. The
4 presentation will be given by Chris Ellsworth and Lance
5 Hinrichs from the Office of Enforcement. They are
6 accompanied by Steve Michaels and Tim Shear, also from the
7 Office oif Enforcement. There will be a PowerPoint
8 presentation on this this morning.
9 MR. ELLSWORTH: I just wanted to make adjustments
10 about the presentation, which will be given by Tim Shear
11 today.
12 SECRETARY BOSE: I apologize for that. Thank
13 you, Chris.
14 CHAIRMAN WELLINGHOFF:: Thank you, Chris.
15 MR. SHEAR: Good morning Mr. Chairman and
16 Commissioners. We are pleased to present the Office of
17 Enforcement's 2010 State of the Markets report. The State
18 of the Markets is staff's annual opportunity to share
19 observations about natural gas, electric and other energy
20 markets. Before we begin, I'd like to mention that this
21 presentation is based on opinions and conclusions of staff,
22 and not necessarily those of the Commission, the Chairman or
23 any of the individual commissioners.
24 In 2010, we saw natural gas supply and demand set
25 new records, while natural gas prices remained moderate

1 through most of the year. We also saw regional changes in
2 natural gas production in new infrastructure, changing
3 utilization along some key pipeline routes across the
4 country.
5 There was also increased demand in the power
6 sector, but a decrease in the amount of power generation
7 capacity added, compared to prior years. Specifically, wind
8 and natural gas fire generation additions dropped off in
9 2010.
10 Though 2010 natural gas prices were up about 12
11 percent on average over 2009, they remained well below the
12 levels of previous years. Natural gas demand increased in
13 2010, and was only partially offset by increased natural gas
14 supply.
15 Natural gas storage levels were high for much of
16 the year, and reached record levels in November. Outside of
17 early winter 2010, and a few days in June, spot prices at
18 the Henry Hub remained between $3 and $5 an mmBtu. By the
19 end of the year, prices remained low, despite a cold start
20 to the winter.
21 As at Henry Hub, average spot natural gas prices
22 rose across the country. In last year's State of the
23 Markets presentation, we highlighted the development of a
24 national gas market due to increases in domestic production,
25 added pipeline infrastructure and increased storage

capacity.

This trend continued in 2010, with regional price differences increasingly reflecting the variable costs of transport between hubs. Prices in the Rockies and lower mid-continent producing regions rose closer to the Henry Hub in 2010, as increased takeaway capacity to higher priced markets lifted local prices.

The difference between natural gas prices in the Northeast and the Henry Hub fell, as increased local production and pipeline capacity gave the Northeast more options to obtain natural gas.

The course of natural gas prices in 2010 revealed an interesting new market dynamic. Through recent years, natural gas prices moved together with other commodities, represented here by the Goldman Sachs commodity index or GSCI. Yet even though the GSCI has doubled in the last two years, natural gas prices have remained relatively flat.

This is a result of several factors. Aside from a small amount of LNG imports at present, the North American natural gas market is self-sufficient, and largely insulated from the international pressures that other commodities face. Strong domestic production growth, combined with added pipeline and storage infrastructure, have increased domestic supply and reduced geographic and seasonal price differences.

Unlike in 2008, natural gas prices appear to be responding primarily to physical fundamentals, namely growing supply from lower cost sources, rather than financial market influences. Also, the graph shows that natural gas prices and coal prices have been converging. This has led to some dispatching of natural gas fire generation before coal fire generation.

Following several years of modest growth, U.S. natural gas demand increased 3.7 percent in 2010. This was driven by a recovering economy that boosted industrial natural gas demand by four percent, and by strong growth in the power sector. There was virtually no growth in residential and commercial consumption.

Though weather conditions can affect year to year demand in the power sector, the use of natural gas to generate electricity has grown steadily in recent years, and now accounts for almost one-third of total U.S. natural gas demand. Increased natural gas generating capacity utilization, the large growth in and lower production costs of proven natural gas reserves, and a flatter forward curve have positioned natural gas generation to increase market share in the power sector.

Natural gas in increasingly edging out coal as the most economical fuel for base load power production in more parts of the country for longer periods during the

year. This added approximately 1.1 to 2.8 billion cubic feet per day on average to total U.S. natural gas demand, over the course of 2010. Given current natural gas and coal prices, this trend should continue in 2011.

U.S. domestic natural gas production grew steadily over the course of the year, from just over 58 Bcf per day in early January, to more than 63 Bcf per day in late December, reaching record highs. This growth can be attributed to increase shale gas production, which accounted for 23 percent of total U.S. production by the end of 2010, up from just 13 percent of total production two years before.

Production from the Haynesville, Fayetteville and Marcellus Basins alone grew more than 7 Bcf per day in the four years from January of 2007 to January 2011. Some market analysts forecast shale gas could account for one-third of total U.S. production by the end of 2015.

This production growth occurred in spite of continued low natural gas prices, because much of the increase in natural gas production in 2010 was associated with natural gas liquids, or NGLs. Natural gas liquids include ethane, propane, butane and natural gasoline, and can add a significant source of revenue to natural gas production, particularly because NGL prices have been increasing with the oil market.

1 In some place, such as the Eagle Ford and North
2 Barnett shale in Texas, and the Bakken field in the Dakotas,
3 the breakeven cost for natural gas has fallen to zero, and
4 natural gas has essentially become a byproduct of oil and
5 NGL drilling. With this trend, we witnessed the shift in
6 drilling from pure natural gas wells to wells that produce
7 both natural gas and NGLs.
8 Over 2010, there were renewed environmental
9 concerns regarding air and water, quality problems
10 associated with both the increased level and methods
11 involved with natural gas extraction, specifically the
12 hydraulic fracturing method used in shale gas drilling. The
13 Environmental Protection Agency, at the direction of
14 Congress, is undertaking a study of this practice, to better
15 understand any potential impacts of hydraulic fracturing on
16 drinking water and ground water.
17 The EPA recently submitted its draft study plan
18 to the agency's science advisory board, with the goal of
19 understanding the relationship between hydraulic fracturing
20 in drinking water resources from the beginning to the end of
21 the drilling cycle, and expects initial research results by
22 the end of 2012, and a final report in 2014.
23 Another aspect of the growth in onshore shale gas
24 is that the U.S. is less susceptible to disruptions in
25 production from hurricanes in the Gulf of Mexico. However,

1 we have seen instances of well freeze-offs, that can have a
2 significant, though short-lived effect, on onshore
3 production.
4 Regional changes in natural gas production and
5 new long haul pipelines are changing utilization along some
6 key pipeline routes across the country. The 1.87 Bcf per
7 day Rockies Express pipeline, which completed its route from
8 Wyoming to Ohio in 2010, displaced natural gas from western
9 Canada, and to a lesser extent the Gulf Coast. That
10 displacement has accelerated with the rapid growth of
11 Marcellus natural gas production.
12 U.S. natural gas can be exported to Canada via
13 backhaul, and a number of proposed new Northeast pipeline
14 projects will export Marcellus natural gas to Canada.
15 Pipelines at most risk for displacement include those
16 flowing Canadian, mid-continent and Gulf Coast production to
17 the Northeast.
18 In Canada, TransCanada filed for a reduction in
19 its long haul rates, to try to keep long haul customers,
20 proposing to make up for lost revenues by increasing rates
21 on short haul customers. In the United States, both
22 Columbia Gulf and Tennessee filed rate increase proposals,
23 citing growing Marcellus production and a need to offer
24 discounts on long haul rates from the Gulf Coast to compete.
25 These pipelines will likely see less utilization

on pipeline segments between the Gulf Coast, the mid-continent and the Northeast, but will likely have higher short haul utilization within the Northeast. This is a trend we will be following as regional shifts in natural gas production continue to impact pipeline utilization on established long haul pipelines with higher transportation costs.

FERC Order No. 720, implemented on October 1st, 2010, required major non-interstate pipelines to begin posting daily nominated receipts and deliveries on their systems. The result was a sharp increase in market transparency. Prior to October 1st, 65 percent of U.S. natural gas supply was visible to the market. After October 1st, this increased to 95 percent, and we now know that interstate pipelines account for approximately 18 Bcf per day of daily U.S. natural gas supply.

This allows the market to estimate daily U.S. natural gas supply much more accurately. In Texas, observable production increased from 5 Bcf per day in the first half of 2010, to more than 17 Bcf per day after implementation of Order 720. We also observed more deliveries to power plants and industrial customers.

Order 720 has successfully increased market transparency and the level of daily market information available to market participants, analysts and regulators.

1 I will now had the presentation over to Lance Hinrichs, to
2 talk about developments in the electric markets.
3 HH Last year, we reported that 2009 wholesale
4 electricity prices fell by half from the previous year. In
5 contrast, 2010 peak hour prices were up on almost 17 percent
6 compared to 2009. Despite this increase, 2010 prices are
7 still roughly 42 percent lower than 2008. The 2010 price
8 rise was primarily related to the previously mentioned
9 increase in fuel prices.
10 However, higher power loads throughout most of
11 the country had an impact, making it necessarily for
12 operators to rely on higher cost generators. As this map
13 shows, the increase in price is not uniform across the
14 country. In the east, a hot summer, along with early signs
15 of a moderate economic recovery, pushed up electricity
16 demand. In PJM, for example, average load was up 4.7
17 percent. Overall, eastern prices rose nearly 20 percent.
18 In contrast, the west experiences a more modest
19 increase in prices due to mild weather. Specifically, a
20 relatively mild summer in California led to a decrease in
21 load of almost three percent compared to 2009. Great spring
22 precipitation in the Northwest resulted in better than
23 expected hydro generation output, which also moderated
24 prices, and even resulted in negative off peak prices at the
25 Mid-Columbia trading hub. Overall, prices in the west were

1 up by six percent.
2 Consumption of electricity in 2010 were due in
3 part to an improving economy. The recession help to drive
4 down consumption from a high in 2007 to a low in 2009, and
5 in 2010, we saw the initial signs of a recovery. Even
6 though industrial demand has not returned to its earlier
7 levels, it is consistent with the economy's 2.9 percent rise
8 in GDP in 2010.
9 Not shown on this chart are the consumption
10 trends for the residential sector, which are primarily
11 driven by weather. After a relatively mild 2009,
12 residential usage was up by six percent in 2010. In
13 particular, the summer months were hotter than normal for
14 all regions but the Pacific coast states. In the Sun Belt,
15 there was record heat, and as a result, the Southwest Power
16 Pool and ERCOT set records for peak demand.
17 In 2016, there was a drop in the amount of new
18 electricity generation hopefully added, compared to the
19 prior year. Overall, plant additions were down
20 approximately 20 percent in 2010, compared to 2009. This is
21 consistent with the effects of a slowly recovering economy,
22 sluggish power demand and tight credit markets
23 While natural gas and wind plants have recently
24 dominated the megawatt capacity share of additions, there
25 was an increase in the amount of new coal fire generation in

2010. These new coal plants came from projects that were the product of a multi-year development process, that was initiated when the economic signals for investment were quite different from today.

Over the past four years, the relative fuel cost advantage for coal plants has decreased, coinciding the previous mentioned increase in shale gas production. In contrast, the development time line for natural gas and wind plants was appreciably shorter. High capital costs reduced load growth and plentiful natural gas supplies have slowed the development of new nuclear facilities.

Over the past several years, the NRC received 19 applications to either construct Or reserve sites for new plants. However, by the end of 2010, several of the developers requested that the NRC suspend review of their applications, and others have indicated that they will not immediately proceed with construction.

Utilities in traditional markets are developing most of the nuclear plants that are still moving forward. In particular, the Southern Company and SCANA have started preliminary work for new reactors at two different sites. Renewable resource additions in 2010 were mixed. For renewable capacity, wind was the leader, adding just over 5,000 megawatts. Despite a 15 percent drop in turbine prices and a continuation of federal tax incentives, this

growth was roughly half the rate of the previous two years.

It was primarily attributable to significantly lower natural gas prices and a weak investment environment. These conditions made it difficult for developers to sign long-term power purchase agreements, which are an important consideration to project financing.

The Midwest ISO added the most wind generation, with an additional 1,500 megawatts, now bringing its systemwide capacity to more than 9,000 megawatts. This now rivals ERCOT as the region with the greatest wind capacity. The systemwide share of wind created between four and eight percent of total energy output in MISO SPP and Ercot.

Solar projects grew robustly in 2010. Grid-connected solar photovoltaics increased at a rate twice that of 2009, adding 883 megawatts. Five states dominated these additions: California, New Jersey, Nevada, Arizona and Colorado, which together accounted for 64 percent of new capacity. Separately, concentrated thermal solar grew by 77 megawatts, the first big jump since the 1980's. In total, there is now more than 2,000 megawatts of grid-connected solar capacity.

This growth has been supported by several factors, which include state-level incentives, favorable federal tax policies, and a 21 percent decline in system costs. In particular, 16 states and Washington, D.C. have

1 provisions for a renewable portfolio or energy standards
2 that specify what percent of their target should be solar
3 generation or distributed resources.
4 Also, utilities tripled their photovoltaic
5 installations to 242 megawatts, as they capitalized on
6 changes that allow them to use federal tax credits and cash
7 grants. In response to the growth in renewables and their
8 role in the markets, the Comission issued a notice of
9 proposed rulemaking for variable energy resources, in Docket
10 No. RM10-11-000.
11 In it, the Commission sought comment on the
12 extent to which barriers might exist that impede the
13 reliable and efficient integration of variable energy
14 resources in to the grid, and whether reforms are needed to
15 eliminate these barriers.
16 RTO capacity markets provide a means for load-
17 serving entities to procure resources to meet forecast load,
18 and allow generators to recover a portion of their fixed
19 costs. In PJM and ISO New England, capacity commitments are
20 for a three year period into the future. New York ISO
21 conducts capacity auctions for the upcoming season in the
22 form of semi-annual seasonal strip auctions.
23 Despite a modest capacity price increase with PJM
24 in 2010, the prices for the forward delivery years of 2012
25 and 2013 and 2013-2014 have generally been steady or

1 decreasing for both PJM and ISO New England. Forecasted
2 load growth rates for both PJM and ISO New England, a key
3 input for determining when new capacity will be needed, have
4 remained relatively flat or declined, reflecting modest
5 economic growth.
6 In the auctions conducted last year for the
7 forward delivery period of 2013-2014, PJM's RTO-wide price
8 was $843 per megawatt month, with locational prices higher
9 in the eastern part of the region. This was up 68 percent
10 from the auction for the 2012-2013 delivery year, but down
11 75 percent from the auction conducted the prior year.
12 ISO New England's price was $2,951 per megawatt
13 month, unchanged from the 2009 auction for the 2012-2013
14 delivery year. For the auctions held in 2010, demand
15 resources, that is, demand response and energy efficiency,
16 accounted for much of the incremental capacity for the
17 forward periods.
18 In PJM, net over retirements ORG ratings, 60
19 percent of new incremental capacity committed was associated
20 with demand response. In New England, 90 percent of the new
21 capacity commitments were also associated with demand
22 resources.
23 Turning to New York, the summer peak load
24 forecast for the state was down 450 megawatts or
25 approximately one percent less than the previous year.

1 Further, in 2010 the New York ISO saw a 900 megawatt
2 increase in capacity resources over the 2009 level. That,
3 combined with a 130 megawatt increase in demand response
4 resulted in a slight decrease in capacity prices for 2010,
5 when compared to 2009.
6 Summer strip prices for New York state were
7 $2,470 per megawatt month, down 18 percent compared to the
8 prior summer. New York City, a notable load pocket, had a
9 large generator discontinue operations, and capacity prices
10 for the summer capability period increased, as anticipated.
11 Demand response resources in the city remain important to
12 the supply demand equation, with more than 480 megawatts of
13 demand response capacity offered at the auction, which is
14 about 20 percent of all demand response resources for the
15 New York ISO.
16 Last year, the Commission approved a number of
17 RTO rule changes on topics ranging from transmission
18 planning and cost allocation, to capacity market mitigation
19 measures. For example, the Commission approved SPP's
20 integrated transmission plan, where SPP conducts 20 year, 10
21 year and near-term assessments to determine transmission
22 needs, particularly for higher voltage facilities.
23 The Commission also approved the California ISO's
24 tariff proposal to create a new category of policy-driven
25 transmission facilities to meet policy requirements and

1 directives. In Texas, ERCOT launched is nodal market
2 redesign on December 1st. That market is, of course, not
3 regulated by the Commission.
4 However, their design is similar to several of
5 the markets that we oversee, and the Division of Market
6 Oversight will follow these developments to observe their
7 results. Major upgrades to the ERCOT model include a
8 transition from a four zone pricing model to one with 8,000
9 nodes, and also the introduction of both a day-ahead market
10 and congestion revenue rates, which are similar to financial
11 transmission rates for FTRs.
12 That completes our presentation. We're available
13 if you have any questions.
14 CHAIRMAN WELLINGHOFF:: Well, thank you Lance,
15 Tim and the full team for this very comprehensive
16 presentation. I appreciate the information as always. It
17 was very useful, very helpful.
18 Questions, comments? Phil?
19 COMMISSIONER MOELLER: Thank you,
20 Mr. Chairman. Well, a year ago
21 the shale issue was emerging,
22 but it's full-blown now, and I serve on the Coordinating
23 Subcommittee of the National Petroleum Council's study on
24 the future of North American natural gas and oil
25 development. So this is a little preview, but that study is

1 going to be coming out this summer or early fall. I'm not
2 going to tease you with any suggested recommendations, but
3 there will be some.
4 In Slide 7, you talked about shale being up to a
5 third of domestic gas production in the next few years. Tim
6 or team, can you elaborate on the assumptions that go into
7 that?
8 MR. SHEAR: That was a pretty kind of a basic
9 model. It took the number of wells added in each basin, and
10 then the production rate of those wells, and essentially
11 extrapolated that data forward.
12 It doesn't take into account whether there's
13 fracking crew shortages or you know, maybe where natural gas
14 prices may move in the forward. It's pretty basic. What
15 have we seen, number of wells, production rate of those
16 wells and then that moving forward.
17 It also doesn't take into account, we've seen
18 huge productivity gains that just takes where we're at now.
19 It doesn't assume that there's going to be more.
20 COMMISSIONER MOELLER: Well, that's one of the
21 things I've learned from the upstream people, is how dynamic
22 this industry is, that the techniques are constantly
23 changing and the efficiency of the wells is subsequently
24 changing and improving over a three month period. They're
25 learning their way. So it's a dynamic area.

1 I recall even about four years ago, people
2 thought break-even prices for Marcellus was $6, and we've
3 heard people making money at $2 now, or could make money at
4 $2.
5 All right, so the next trend appears to be
6 liquids, and how we deal with them. Do we have enough
7 processing capacity and pipeline capacity to deal with them?
8 MR. SHEAR: I think that really varies by area.
9 It's hard to kind of make a national yes or no answer. We
10 saw actually record NGL production last fall, but it really
11 varies by play. If you take say the Eagle Ford shale in
12 South Texas, there does seem to be the infrastructure in
13 place. That won't be a constraint there. The Bakken Field
14 in the Dakotas is a little different, with increased
15 production there. They may have to add infrastructure.
16 And in the Marcellus, you actually probably see
17 the most constraints there potentially going forward,
18 because there's no-- ethane is used in petrochemical plants.
19 There's no ethane market in the Northeast. So that ethane
20 is going to have to be moved either to the Gulf Coast or
21 Southern Ontario, where there are petrochemical facilities.
22 So going forward, that will need to be addressed,
23 and there are several proposals to deal with that issue,
24 that are kind of in some stage of development.
25 COMMISSIONER MOELLER: So our Office of Energy

1 Projects will remain busy on this subject matter. Speaking
2 of that, the next slide refers to pipeline projects moving
3 Marcellus shale. Without getting into specifics, I don't
4 want anybody to be uncomfortable, what are the parameters of
5 how many we're talking about and the kind of capacity
6 involved? That may be a question for Jeff too. I'm not
7 sure.
8 MR. SHEAR: I can, I guess, give a really general
9 answer. With the growth we've seen in Marcellus and the
10 forecasts going forward, essentially all the pipelines in
11 that area have tried to kind of accommodate that growth.
12 Whether it be kind of expanding the capacity on their
13 existing systems, or adding new pipelines, or even kind of a
14 like bidirectional flows or reverse flows.
15 So I think the idea there going forward is you're
16 going to move gas essentially north out of the Marcellus and
17 through the Niagara region into Canada.
18 WW Just following up on what Tim said, we have
19 had a handful. It's not an avalanche of projects. We have
20 approved, I believe on the Iroquois and the Empire systems,
21 exports to Canada, which of course required a Presidential
22 permit. That was, needed that ascent of the State
23 Department and Defense.
24 We have a couple pending. I want to note.
25 These, as Tim said, these aren't Greenfield pipelines.

1 These are existing pipelines that, through a little bit of
2 facility modification can easily have bidirectional flow. I
3 would note that we have had flows to Canada for quite some
4 time. It's just the kind of motor this time is domestic
5 production.
6 So we can also provide you and the other offices
7 with a list of the projects that would involve exports to
8 Canada because of Marcellus.
9 COMMISSIONER MOELLER: Well, this is emerging
10 issue. It's exciting, and I probably have a few more
11 questions, but I'll cede my time. Thank you, Mr. Chairman.
12 CHAIRMAN WELLINGHOFF:: Anybody else, questions,
13 comments? Cheryl.
14 COMMISSIONER LaFLEUR: Thank you, Lance and Tim
15 and everyone on the team. I'm sort of picking up on
16 Commissioner Moeller's question. In part driven by all the
17 shale gas and the reduction in gas prices and driven by
18 other factors as well, we're becoming more and more
19 dependent on natural gas as the primary fuel for
20 electricity, and you mentioned that in your presentation.
21 We certainly, I certainly expect to see a lot more of it.
22 I think there's an assumption developing that gas
23 prices can only go down, and everything's going to be
24 wonderful and it will be flat forever because of all the
25 shale. But it was only in the last decade we saw a real

1 price spike in natural gas. I wonder if you could comment
2 on what are the major risk factors we should be thinking of,
3 in the availability or affordability of natural gas? I mean
4 I know Yogi Berra said don't make predictions about the
5 future, but I'm interested in your thoughts.
6 MR. SHEAR: I'll let Chris take this one.
7 (Laughter.)
8 MR. ELLSWORTH: I think, you know, some of the
9 major issues that face, you know, this really good future
10 for shale gas, what we're seeing right now are some
11 shortages on completion crews, particularly fracking crews.
12 So currently we're seeing quite a large backlog in wells
13 that have been drilled but not completed. Some estimates
14 put it as high as 5,000.
15 In some respects that's good news, because once
16 those fracking crews get to those wells, that will release
17 more supply into the market. Another, I think, big question
18 mark over shale gas is the release of the EPA study, and
19 what that means for fracking.
20 We've talked about it internally; we don't think
21 it would kind of stop the growth in shale gas necessarily.
22 But it may require producers to implement new procedures for
23 fracking that could add to that cost, and therefore
24 potentially prices.
25 Another thing we've seen is we've seen a movement

1 to capital, away from pure gas drilling, more to oil and NGL
2 drilling. So I think that's something that should be
3 watched in terms of potential price impacts. Then on the
4 horizon, we started to see more potential LNG export
5 projects. So people are talking about LNG export projects.
6 That's an interesting subject, because one could
7 potentially see a rise in U.S. gas prices or a convergence
8 of U.S. gas prices to global gas prices. Currently, they're
9 about a third to a half of what global gas prices are. But
10 that very much depends, that's kind of very much depends on
11 how much export capacity you're talking about.
12 Continued growth in LNG production and demand
13 here and other things. But people are talking about that.
14 COMMISSIONER LaFLEUR: Thank you. You answered
15 my second question too. So all right, thank.
16 MR. ELLSWORTH: Okay.
17 CHAIRMAN WELLINGHOFF:: Dr. Spitzer.
18 COMMISSIONER SPITZER: Thank you, Mr. Chairman,
19 and I'd further make an observation, I suppose, based upon
20 the comments and the questions of my colleagues. We have a
21 national natural gas market that didn't exist in the past,
22 and it's a consequence of the alignment of the industry with
23 FERC's regulatory policies that have been very consistent
24 and stable for a long period of time.
25 I think the primary credit for the shale

1 revolution with the benefits to the ratepayers, both in
2 terms of environmental benefits as well as economic
3 benefits, rise from the industry industriousness and
4 creativity of this sector of the economy, but also, as
5 Commissioner Moeller pointed out, the Office of Energy
6 Projects provides a strong leadership role.
7 In my travels across the country, I've heard
8 nothing but positive comments regarding our Office of Energy
9 Projects, and their commitment to protecting the environment
10 and at the same time moving forward with the infrastructure
11 necessary to create the national market.
12 We don't know what the next greatest thing is
13 going to be. Obviously, shale was a great success. In
14 terms of analogizing to the electricity sector, I think a
15 lot of the undertakings at FERC on innovation, on
16 electricity provide the same paradigm with consistent stable
17 regulatory policies aligned with markets, to create the next
18 best thing.
19 We don't know what that's going to be, but we do
20 know that if markets and regulation are aligned correctly,
21 the next great thing could be again, some unforeseen benefit
22 to the ratepayers. In terms of the direct, demonstrable
23 benefits in this report arising from natural gas, in
24 addition to the gas sector, the folks that work inside this
25 building deserve a lot of credit. I'd like to thank them.

1 CHAIRMAN WELLINGHOFF:: Commissioner Norris.
2 COMMISSIONER NORRIS: Thanks. I think you
3 answered all my questions previously. I just had a couple
4 of observations I'll make, and one is it's, at least my
5 takeaway from this is we're going to -- we are and going to
6 continue to have more on gas for meeting many energy needs.
7 Interestingly, enough, it's displacing coal just on cost
8 right now, but also as a backup for generation for variable
9 integration renewables, in response to the EPA rules.
10 So we're going to increaser this reliance on gas,
11 and I just think we need to make sure we're mindful of, you
12 now as Cheryl pointed out, we have a history of some
13 volatility on price with gas, but with the increased
14 reliance, we're going to have, I think, increased pressure
15 on us to watch how it impacts reliability, and the pipeline
16 infrastructure.
17 Stacking a number of generation plants on one
18 pipeline certainly probably yields a large single
19 contingency factor than we have planned for in the past. So
20 I think we have to keep that in mind, and figure out how
21 we're going to coordinate, more than we have in the past
22 across electric and gas sectors, to deal with reliability.
23 The second observation is, as you noted, demand's
24 gone down. You've see a 20 percent drop in plant additions,
25 and also we've seen demand response become a key player In

1 responding to our capacity needs. But we also, with the
2 downturn in the economy, there's more likelihood that people
3 are going to displace production, and respond with demand
4 response, keeping mindful going forward of what happens when
5 this economy turns around, and can we still rely on demand
6 response, although I'm a great supporter of it, to meet all
7 of our -- to meet our peak capacity concerns, or what it
8 means, in terms of addressing capacity markets and long-term
9 generation needs, that hopefully gas can solve a lot of
10 these problems.
11 But I think we have to make sure we're planning
12 for it. But thanks very much for working this. It's very
13 informative.
14 CHAIRMAN WELLINGHOFF:: Thank you, Commissioner
15 Norris. Anyone else have any comments or questions of the
16 panel?
17 (No response.)
18 CHAIRMAN WELLINGHOFF:: Thank you, panel. I
19 appreciate it very much. Anything else to come before us?
20 SECRETARY BOSE: No, Mr. Chairman.
21 CHAIRMAN WELLINGHOFF:: If not, this meeting is
22 adjourned.
23 (Whereupon, at 10:48 a.m., the meeting was
24 adjourned.)