BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

REVIEW OF WHOLESALE ELECTRICITY : Docket No.

MARKETS : AD08-9-000

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Hearing Room 2C

Federal Energy Regulatory Commission

888 First Street, N.E.

Washington, D. C. 20426

Tuesday, July 1, 2008

The above-entitled matter came on for conference, pursuant to Commission Order, at 9:45 a.m., Chairman Joseph T. Kelliher, presiding.

PRESENT:

Commissioner Philip D. Moeller

Commissioner Suedeen G. Kelly

Commissioner Marc Spitzer

Commissioner Jon Wellinghoff

P R O C E E D I N G S

(9:45 a.m.)

CHAIRMAN KELLIHER: Good morning. I apologize for being a little late today. We try to be timely here at FERC, so I regret that.

The purpose of this conference is to review the state of wholesale power markets in various regions of the country.

The United States does not have a national power market; we have regional markets, and there are significant differences among the regions.

Some of these differences relate to market structure, others to industry structure, and electricity supply fuel mix.

All of our regional power markets, rely on a mixture of competition and regulation to assure reliable electricity supplies at a reasonable cost, however, the nature of these competitive markets is quite different, and the U.S. has hybrid wholesale markets.

Organized markets cover most of the country, serve most of our country's population, and power most of our economic activity. Regional Transmission Organizations and Independent System Operators, were established for a variety of purposes, including: Improving reliability; reducing the prospect of undue discrimination and preference in transmission service; improving grid access; establishing broader regional power markets; improving market access; and increasing market transparency.

Today we will hear about the continuing progress by RTOs and ISOs in these areas. I've been impressed by the steady progress made in the organized markets on a number of fronts.

The West and the South do not have organized markets, but these regional power markets also rely on competitive forces, to varying degrees. The Commission is as interested in the state of wholesale markets in these regions, as in the organized markets.

So, today, we're really looking at all of the different wholesale markets in the United States, with two exceptions: The great state of Texas, which was formerly independent and is very keenly aware of their nine years of independence, where we have limited jurisdiction, but we're interested in the success of the Texas model; and also the Tennessee Valley, the one region where there is not a competitive wholesale power market, by the operation of federal law.

But as we examine the state of competitive wholesale power markets, we must consider how best to evaluate these markets. In my view, retail price movements are poor measures, since these movements are largely dictated by changes in capital and fuel costs, and are heavily influenced by state regulatory policy.

The better measure is more complicated, namely, weather, and wholesale power markets demonstrate the characteristics of competitive markets, and, if so, we can conclude that wholesale markets are subject to effective competition.

But then that begs the question of what's the correct measure, what are the characteristics of competitive markets?

In my view, they'd include the following: The level of generation entry; the extent of generation fuel diversity; the extent of market access; the quality of grid access; the strength of the power grid itself; the level of grid investment; improvements in operating performance of both generation and transmission; level of market transparency; the reliance or on or extent or penetration of demand response; the availability of new products and services; and the deployment of new technologies.

Now, in my opinion, both the organized markets and the Southern and Western Regional power markets, should be evaluated on the same basis and by applying the same characteristics.

My expectation is that we will be able to identify whether regional wholesale power markets have these characteristics, and I also hope we'll be able to identify areas where significant progress has been made and where further improvements are needed.

I don't expect, though, at the end of the day, that we will conclude that perfect competition governs regional wholesale power markets, either in the organized markets or in the West or the South, but my hope is that we will determine whether regional wholesale power markets are subject to effective competition, and be able to identify some changes or reforms that can send us down the path to more perfect competition in each market.

I look forward to hearing the statements of our witnesses today. Colleagues, comments? Commissioner Moeller?

COMMISSIONER MOELLER: Thank you, Mr. Chairman.

For both this panel and subsequent panels, I want to recognize not only the heads of the RTOs, but the Market Monitors, for being here, and basically want to compliment them on doing the job of trying to promote competitive markets.

The markets are under attack, but they do deliver to customers in a way that non-competitive markets do not. So the markets themselves benefit consumers, and the market monitors benefit consumers. But how are we improving transmission and how are we getting more transmission built, and what are you doing, potentially, to educate consumers on the benefits of markets? What's the carbon debate doing to impact how you go about your business?

My concern is that the uncertainty over that, is leading us to more dependency on natural gas.

Finally, if you have comments on how the new reliability rules and standards, which are so significant, how they affect your operations. That also will be of interest, but I thank the Staff for putting this together, and particularly the panelists this morning, and, subsequently today, for the effort to be here.

Thank you, Mr. Chairman.

CHAIRMAN KELLIHER: Thank you. Colleagues? Commissioner Wellinghoff?

COMMISSIONER WELLINGHOFF: Thank you, Mr. Chairman. Again, I want to thank the panelists for being here today. I'm very anxious to hear what you have to say, and I think it's apt that we have this discussion on competitive markets, because I think those markets are healthy, but I think they can be healthier.

One thing, of course, that I have talked about for making it healthier, is improving the level of demand response, and I know you're all interested in that area, and I'm interested in hearing from you on that area.

I think another interesting thing that I've kind of picked up on, is that not only do we have healthy competition, but we have healthy competition between and among the RTOs on different variants in how those markets should operate, and I think that's a good thing.

We have different experiments going on in different areas, that show us how these things can work best, so that we can learn from each other.

And so I'd also be very interested in hearing about best practices and how you look at sharing best practices for how these markets operate. I think that's an essential thing for us to do.

I want to apologized ahead of time that I'm going to have to leave a little bit before noon. I'm very interested in what you all have to say, but I do have an appointment then.

I'm also going to have to leave at about 3:00, but I'll be here for as much of the day as I can, so thank you all for coming.

CHAIRMAN KELLIHER: Thank you. Colleagues? Commissioner Spitzer?

COMMISSIONER SPITZER: Thank you, Mr. Chairman.

I would associate myself with the comments of my colleagues so far, and don't want to repeat those observations that I agree with.

I would like to make a few points. An

interesting aspect of facet of energy, is the regional nature of energy throughout the country, and the policies are generally organized upon a regional basis, and it's particularly effective to have these regional presentations, and yet try and draw from the regions, some aggregate observations that can help FERC frame national energy policy.

It's been pointed out by the Chairman, that we're in an environment of rising fuel prices, rising commodity prices, rising construction prices, as well as increased capital costs, and so the question is not where are the prices -- we know they're going up across the country in both organized and non-organized markets -- the question is the degree to which the RTOs have mitigated price increases and what would -- I would describe as the lawyers use the term, "but for," but for organized markets, where would the prices be? I think that's a more accurate question to pose, as opposed to the wringing of hands over increased prices, notwithstanding the fact that increased retail prices impose burdens on ratepayers, that we recognize.

They create various pressures on state commissions, that we recognize. But often, within these -- within turmoil, comes opportunity, and we've seen some opportunities, and, particularly, the recent response with regard to demand response in the forward capacity market in

New England, is, I think a reflection of it, of opportunity arising from concerns.

I would agree that it is not delineated in these reports, but I would be interested in observations from panelists in this panel and subsequent panels, regarding what I would describe as the carbon contingency scenario.

I know it's difficult to project the future, but we would expect some federal legislative developments, and the question would be, what would be the response in terms of fuel diversity, upward pressure on natural gas, the degree to which renewables and demand response, would be incorporated into that.

Obviously, there's been a great deal of discussion and efforts on the transmission grid, that we all support, and those discussions are helpful, and particularly in the West and the South, this afternoon, the Order 890 panels, I think, have been very effective.

So I look forward to the discussions. I think this -- we have, clearly, challenges, but, again, challenges give rise to opportunities.

One final point I'd make, is, Commissioner Wellinghoff has done a lot of work with regard to vehicle-to-grid, and his evangelism has resulted in a new convert, and I'm extremely interested in this, as not only a means of assistance to the electricity sector, in terms of baseload generation, procuring baseload generation, in order to deal with vehicle-to-grid, but the transportation sector.

We have to take notice of the great costs to society, and that I think it's a great opportunity for the electric sector to provide relief to the American economy, and it again highlights the massive importance of the electricity sector.

I'd like to know from the panelists -- I know there have been great -- in organized markets, and the transparency with regard to metering and ancillary services, opportunities for vehicle-to-grid and potentially other technologies, and I'd be interested in your observations on that. Thank you, Mr. Chairman.

CHAIRMAN KELLIHER: Thank you. Commissioner Kelly?

COMMISSIONER KELLY: Thank you, Joe. Well, I think the timing of our meeting today, is particular auspicious. A week and a half ago, our Staff released a report describing the rising costs all across the electric industry, that consumers, utilities, all participants in the industry, are facing.

And as I remarked then and I wholeheartedly believe, the most important thing that we, FERC, can do in response to that, is to work to ensure a robust, competitive wholesale market.

So I thank you for your presence today, and I look forward to hearing your reports and your remarks.

CHAIRMAN KELLIHER: Great, thank you. Well, we'll start with ISO New England and I'd like to recognize Gordon van Welie, the President and Chief Executive Officer, and then he will be followed by Hung-po Chao, the Director of Market Monitoring at ISO New England. Gordon?

(Slides.)

MR. van WELIE: Good morning. Hung-po and I are pleased to meet with the Commission today, to outline New England's progress to date, in the development of competitive wholesale electricity markets and the improvement opportunities and challenges that remain.

We have split the presentation into two parts. I will cover a broad overview of progress in New England since the introduction of wholesale electricity markets, including how we are meeting our objectives; the infrastructure and process improvements that have resulted from competitive markets in our regional planning process; and the results from our forward capacity market.

I will then speak to the challenges and opportunities that face the region. Hung-po will cover the details of market performance during 2007, and make some recommendations on areas where our markets can be improved.

The ISO was established to meet a range of very specific objectives. These include: Providing for reliable system operation, 24x7 by 365; the provision of long-term regional planning; open, nondiscriminatory grid access; the oversight and administration of efficient and fair markets; ensuring that we provide transparent information to our stakeholders; and, of course, overseeing and administering a very robust stakeholder process.

I believe that we are meeting all of these objectives. During the course of the presentation, I will elaborate on a number of these objectives and will also describe how they benefit the region.

Markets have resulted in significant investment in much-needed infrastructure in New England. During the 1980s and the 1990s, the region retired three nuclear power plants and a number of oil- and coal-fired plants, resulting in a rapid reduction of our reserve margins.

At the same time, demand was growing rapidly. Markets attracted private investment in approximately 10,000 megawatts of new gas-fired generation in New England in the period from 1990 to 2003.

Consumers were shielded from the risk of poor investment decisions, and it is interesting to note that there were a number of bankruptcies declared by merchant power plants during this period, kind of underwriting this point.

We've been working hard on stimulating and integrating demand resources in our region, and this slides shows the progress we have made over the last seven or eight years.

We have grown the demand response resource base from about 100 megawatts in 2000, to around 1700 megawatts today, and this does take account of the additional resources we have added through the forward capacity market. I will elaborate on that in a little while.

We continue to see rapid growth in those resources. This presents us with both an opportunity and a number of challenges, which I will elaborate on.

I'd like to move to transmission. This is a busy slide, and it shows the major reliability transmission projects we are working on in New England. In total, the transmission owners the ISO have added over 200 projects in all the New England states since 2002, and I'd like to just briefly explain the major projects depicted on this slide.

The solid lines are the lines that have already been put into service. Now, this includes Southwest Connecticut Phase I; the NSTAR Project into Boston, which is 3-A, the Vermont Project, four, and the second tie to New Brunswick up in Maine, five.

The projects that have got the short dots, are the ones that are currently under construction. This includes No. 2, which is Southwest Connecticut Phase II; the improvements in the Monadanock Region in New Hampshire; and some work that's going on in lower southeastern Massachusetts.

And then the lines that have got the longer dashes, are the lines that are currently in the planning phase and proceeding through siting, and that will include the NEEWS Project, which is the New England East-West solution in the central part of Massachusetts and Connecticut, and then the Maine Reliability Project, which is No. 9 on this chart.

What does this mean in terms of dollars? Well, as of the end of last year, we had $1.2 billion worth of transmission in service, and that represented those solid lines on the previous chart.

And the remaining lines on that chart, represent almost $6 billion on the horizon.

Of course, this is a significant investment for the region, and we need to work together with our stakeholders and the transmission owners, to ensure that the investments are cost-effective.

Also, the ISO does not achieve this on its own. We have achieved this through a transparent and collaborative regional system planning process that is open to all our stakeholders.

And this brings me, generically, to the topic of the stakeholder process. We have a highly developed and extremely robust stakeholder process in New England. Every aspect of our business operations is reviewed with our stakeholders, and this includes market and system operations, the performance of the system, as well as the ISO, the needs of the bulk power system, and anything to do with developing or changing the market design within New England, is reviewed extensively through our stakeholder process.

Our stakeholders also have the opportunity to advance their own proposals through the stakeholder process.

One of the other things which is noteworthy, which I realized is not often visible outside of New England, is that our stakeholders are also directly involved in the selection of our independent Board of Directors.

We changed our governance in February of 2005 when we became an RTO, from a system where the Board was self-selecting and self-perpetuating, to a system where the Board works with representatives from each of the NEPOOL sectors and a representative from NECPUC, to nominate a slate of Directors that is presented first to NEPOOL and then finally to the Board for a vote.

This Joint Nominating Committee, as it is called, has been instrumental in successfully managing the recruitment of five Directors since 2005, which is approximately half of our Board.

We've also established a practice of reviewing our five-year business plan and our annual business plan and budget, every year, with our stakeholders.

The process commences in early Summer, and results in a presentation of the next year's annual budget to NEPOOL and NECPUC in the Fall.

NEPOOL votes on our budget in October, and we also seek feedback from NECPUC during the course of the Summer, prior to the Board voting on the budget in October.

The process culminates at the end of October, with the Section 205 filing on our annual budget, where we seek Commission approval for the next year's budget.

As you can see, we have a transparent and robust stakeholder process, and this has proven invaluable to us in developing effective wholesale electricity markets in the region.

At this point, I would like to segue to give you a progress update on a groundbreaking market development in New England, the forward capacity market.

As you know, the forward capacity market is a result of a Commission-sponsored settlement proceeding that culminated in a regionwide agreement to the development of a new forward capacity auction for the Region.

There are three phases to the implementation of the FCM. The first phase concluded with a successful running of the first auction in February of this year.

The second phase comprises the implementation of reconfiguration auctions, the bilateral transactions, and the running of the second auction in December of this year.

The third phase will result in all the settlements offering business processes being in place by June of 2010.

This slide shows you the results of the first auction. The first auction cleared just over 1800 megawatts of new resources, and what was very interesting, was that roughly two-thirds of this was demand resources, and one-third supply resources.

As you can see by the slide, the bulk of the resources are located in high-demand states, namely, Massachusetts and Connecticut, and this is exactly the type of pattern we would hope to see.

We were pleasantly surprised by the strong showing by demand resources, since this is exactly what the Region needs, and Hong-po will expand on that later on, however, the rate of development of this sector of the resource base, is well beyond our initial expectations and we realize that this will result in integration challenges for us, both in the area of ensuring reliable operations and in terms of addressing the issue of price formation in day-ahead and real-time markets, which is one of the next challenges we have to address.

This is a very interesting slide, as well. The slide depicts the breakdown of demand resources, into active demand response, which comprises load management and distributed generation, and what we would refer to as passive demand resources, in other words, energy efficiency.

I think it's very pleasing to note that almost half the demand resources are energy efficiency. The other item of note on this slide, is that over half of the demand resources are merchant, a clear sign that wholesale markets are attracting merchant investment in the demand side of the market.

This slide shows the resources that have submitted qualification packages to compete in the second auction in December of this year, and you can see we have over 12,000 megawatts, and, once again, a healthy showing by demand resources, and we're expecting another round of robust response by both supply and demand resources.

So, just to summarize, looking back at our progress to date, I think it is evident that the combination of competitive wholesale markets and the robust regional system planning process, is resulting in infrastructure and resource investment in the right locations in New England.

In addition, we have seen efficiency improvements in operations, including substantially improved availability of our generation fleet, and Hung-po will expand on this point in his presentation.

This has been accomplished without sacrificing reliability in New England, and, arguably, we have, in fact, strengthened reliability.

I think this is significant progress for the Region, but we can't afford to rest on our laurels, because we still have major challenges ahead of us.

And with that, what I'd like to do, is move to some of the challenges that we face.

The Region made a major shift into natural gas-fired generation over the past decade. This has resulted in efficiency improvements and cleaner air in New England, but it has also brought a number of operational and economic challenges.

I think our experience in New England is instructive to the rest of the nation, as we contemplate a future where we start to shift out of coal-fired generation, into gas-fired generation.

This slide shows that almost 50 percent of our current installed capacity, is gas-fired, and less than half of that is capable of running on both natural gas and fuel oil. This latter point is an operational vulnerability for us in the Region, since we are at the end of the gas pipelines and are vulnerable to gas supply and transportation interruptions. This is an issue that we have to solve for within the Region.

In addition, when we examine our generator queue and the supply resources that have cleared or have qualified for the forward capacity auction, we can see that natural gas-fired resources dominate new supply proposals.

There are two reasons for this: The first reason is that natural gas-fired resources, are still, overall, the most cost-effective and lowest-risk supply resources in the short run, although this may change in the longer run, if we see that the gas price continues to run up.

The second reason is that it's extremely difficult to site and build anything else in New England. On the latter point, as gas prices have risen, we have seen sharp increases in electricity prices, and this, coupled with the financial incentive resulting from state environmental mandates, has caused a significant interest in the integration of renewable resources within the Region. I will return to this point later in the presentation.

The New England states are amongst the most progressive in the nation, in terms of setting increased environmental standards for the generation sector. In addition, due to the fact that approximately 60 percent of our generation resources burn either gas or oil and are the marginal resource, almost 90 percent of the time, we have seen a high level of price volatility in the electricity markets, which creates a great deal of concern about the economic impact on households and businesses in New England.

Thus, policymakers in the Region, have begun searching for and stimulating investment in resources other than natural gas resources, that will target what I call the sweet spot at the intersection of those three circles there -- the economic, environmental, and reliability goals that we are striving for.

Hurricanes Rita and Katrina brought the price issue sharply into focus in the Winter of 2005 and 2006. We saw natural gas price increases from roughly $7 per million BTU to approximately $14 per million BTU, in a matter of a few weeks.

This cost increase was immediately reflected in wholesale electricity prices, and, shortly thereafter, appeared as increases ranging from 25 to 50 percent in the retail rates.

As you can imagine, there was great concern about this amongst New England policymakers. Unfortunately, in some quarters, this turned into an attack on competitive wholesale markets, on the presumption that there was something awry, that could have been avoided, had the Region not chosen to restructure.

We realized that we needed to do a better job of informing policymakers on the real causes for the price increases, and also educate policymakers on the options open to them to mitigate these price increases.

This led to a series of studies that we conducted with our stakeholders, called Scenario Analysis. We formed a stakeholder working group of over 100 participants, to examine the regional effects of different future resource choices in the Region.

We performed thousands of production cost runs and analyzed the impact of different resources on reliability, wholesale prices, and the environment.

It was a very interesting study and it produced some really valuable results. I won't go into the details, but if anyone is interested, they can find a copy of it on our website.

But I would like to summarize some of the guidance that resulted from this study: First, the Region will continue to depend on natural gas for its electricity supply, and that the price of gas and oil will likely drive the price of electricity in the Region for the foreseeable future.

The analysis also demonstrated that it will be a challenge to satisfy the requirements arising from state renewable portfolio standards and the Regional Greenhouse Gas Initiative.

It really boiled down to the following four points, and I would say that this is the bottom line for the Region: The first is, we have become more energy efficient; secondly, we have to reduce our reliance on high-cost fossil fuels, and we have to build and/or access non-carbon-emitting resources; and, finally, we have to examine the cost of transmission to enable access to renewables within the Region or outside of the Region.

Unfortunately, the most promising renewable and non-carbon-emitting resources, are in places where we do not have robust transmission infrastructure. We also recently received direction from the Commission, through Order 890, that we have an obligation to conduct economic transmission studies for the Region.

This has led the ISO to propose a framework for planning the expansion of our transmission network, and we have initiated a stakeholder working group to tackle the many issues inherent in this very complex subject.

The transmission planning framework consists of three tiers: The first tier comprises the projects that are needed to ensure reliability and compliance with NERC and NPCC standards, and you saw these projects on an earlier slide.

The second tier comprises the interconnection of renewable resources within the Region, and the third tier would comprise investing in stronger transmission ties with our neighbors.

This slide overlays Tier II and Tier III projects, onto the Tier I reliability projects, so it makes the slide even more busy. Unfortunately, it's not possible to go into this in any detail at this time, but suffice it to say that this has sparked a very vigorous debate about the economics, viability, and appropriateness of Tier II and Tier III projects, and what the ISO's role should be this area.

The other thing I'd like to draw to your attention, is that it's not that our participants i the states, are standing still, scratching their heads, and not knowing what to do; they're taking action.

The states have already taken or are in the process of taking action to address the issues identified in the Scenario Analysis. One example is recently proposed legislation in Massachusetts, that will set a requirement that by 2020, 25-percent of electric load will have to be satisfied by demand resources and 20 percent by renewable resources or alternative energy generation.

In addition, we see ample evidence that

investors are aggressively pursuing renewable and non-carbon-emitting resources and the transmission investments that this will require.

What remains to be seen, is whether the transmission investments will be economically viable. There are some who would have the ISO take a more proactive role in this discussion over economic transmission investments, and others who would have the ISO remain neutral and essentially a provider of information and possibly a facilitator.

At this stage, I would say that the weight of the input is in the direction of the ISO remaining as a provider of information and a facilitator and not a decisionmaker.

Needless to say, we will continue working through these issues with our stakeholders, and I think we ultimately may need further clarification from the Commission as to what you see our role being in this area.

This slide summarizes what I see as being the high-level challenges and opportunities facing the Region and the ISO. The first is the integration and reliable operation of substantially increased levels of active demand-response resources.

This will also bring with it, the need to solve for the issue of price formation in the energy spot markets. We need to have additional gas-only generation, become dualfuel-capable.

There is the significant promise of non-carbon-emitting and renewable resources. This will present both an operational challenge, in the case of wind, and an investment challenge, in terms of required transmission investment.

Finally, it's important that we do achieve consensus on how we will deal with the so-called economic transmission investments that we are currently studying.

At this point, what I'd like to do, is hand it over to Hung-po.

(Slides.)

MR. CHAO: Thank you, Mr. Chairman and Commissioners. As Gordon has provided a broad overview of the ISO New England market's progress and the future prospects, I'm going to present the Market Monitor's assessment of the performance of the wholesale electricity markets in New England.

First, an overview: The New England wholesale electricity markets continued to perform competitively in 2007, responding to changing supply and demand conditions, while supporting reliable grid operations.

The set of wholesale electricity markets operated by the ISO, is now essentially complete, with the introduction of the forward capacity market, designed to promote investment in new supply and demand resources.

Transmission enhancements relieved the local constraints and resulted in improved system reliability and market efficiency.

As I will discuss in more detail later, the ISO's wholesale power markets have produced tangible benefits by sending transparent price signals to consumers and investors alike, and providing incentives for better generation performance.

Based on the market experience so far, I will also discuss opportunities for further improvements, and review remaining industry challenges.

Overall, the 2007 market prices are consistent with the marginal costs, an outcome that is consistent with competitive markets. The Market Monitor also calculates a variety of benchmark indices to gauge market competitiveness.

During 2007, the key indices provided empirical evidence for the competitiveness of the markets and the presence of strong incentives for new market entry.

To ensure that the market remains competitive, the Market Monitor is charged with discovering and mitigating the participant behavior that compromises the competitiveness of the markets.

Anticompetitive market behavior remains

relatively infrequent in New England. Mitigation was triggered only 16 times in 2007. These mitigations were normal and raised no specific concerns about the competitiveness of the market.

In addition, nearly daily discussions were held concerning specific market behaviors of individual participants.

On the other hand, existing mitigation rules or uplift, the out-of-market net commitment period compensation, created adverse incentives and need improvement.

Because natural gas is most often the marginal fuel in New England, setting marginal prices 74 percent of the time, electric energy costs are tightly linked to the price of natural gas.

This figure illustrates the close relationship between electricity prices and natural gas prices, which is consistent with the competitive market in which prices are determined by the marginal costs.

The peak in 2005, is from Hurricanes Katrina and Rita, and the gap between the electricity prices and natural gas prices in the summer of 2007, reflects the fact that oil prices have been growing faster than that of natural gas.

As a result, when oil-fueled units are needed to meet the summer peak loads, electricity prices are higher than would be expected from generation fueled by natural gas.

This figures shows that variation among fuel-adjusted yearly average wholesale electricity prices has been considerably less than among unadjusted prices.

This result indicates the benefit of a competitive market for producing efficient and stable price signals for investment.

This figure shows the all-in cost metric for the wholesale electricity energy that load-serving entities with real-time load obligations, paid in 2005 through 2007.

The wholesale cost dropped 20 percent from 2005 to 2006, but rose 12 percent from 2006 to 2007. Energy cost are, by far, the largest component of all the all-in wholesale cost matrix, accounting for 84 percent of the total in 2007.

Beginning in December of 2006, under the forward capacity market current agreement, negotiated transition payments for capacity, have been implemented. Consequently, capacity payments rose significantly, accounting for 11 percent of the total cost in 2007, compared with two percent in 2006.

The transition payment was offset by a reduction of $214 million in that reliability agreement payments. The energy and capacity cost components, account for 90 percent of the cost increase in the costs.

Further benefits could be achieved through closer integration of the wholesale and retail markets, so that consumers can see the right prices with the transparency of the energy that they are using.

Another undisputed benefit of competitive wholesale electricity markets, is increased generation availability. Specifically, market competition offers a significant incentive to improve generation availability and thus reduce the amount of new investment needed by the system.

Well-maintained generating resources, enhance an individual generator's revenue from providing electric energy regulation, reserve services; conversely, reduced availability will lower the capacity payment, as well as revenue from sales.

As shown in this figure, generation availability is generally happening, ranging from a low before the year 2000, to a new high of 90 percent in 2007.

The net energy for load supplied by the system in 2007, increased 1.9 percent from 2006. As shown in the top line of the curve, the decline in energy use in 2006, from 2005, was a response to the large increase, about a 20-percent increase in retail electricity prices, while the wholesale electricity prices declined 20 percent.

The high 2006 retail price, represents a lag response to the increased costs of electricity as reflected in the wholesale electricity market. This is the first decline in energy use not associated with an economic recession during the past two decades.

We believe that this provides strong evidence that consumers' demand can respond to prices vigorously, when the chances are given.

This figure shows historical load factors for New England. Because peak demand has been growing disproportionately compared with the average demand, load factors have been declining.

Load growth and the declining load factor, creates demand for additional new capacity, and will ultimately result in load capacity utilization, less efficient use of resources, and high total electricity costs for consumers.

Closer linkage between retail and wholesale markets, is needed to enhance demand response and market innovation to consumers' advantage.

One possibility for efficiency improvement, is to let retail rates appropriately reflect the wholesale prices, so that consumers can respond to price signals that are consistent with the marginal costs.

ISO New England electricity markets, are entering a new phase. During the initial phase, now largely complete, market design efforts were based on a theoretical ideal.

Now the focus is on making market improvements and simplification based on careful assessment, where success is in terms of improving the status quo. In particular, as I mentioned earlier, daily reliability payments, so-called uplift charges, including net commitment period compensation, are intended to compensate generating resources that do not recoup their fixed -- their costs through their offers.

They are not intended to create incentives that will have impact on price formation. As I mentioned earlier, recent experience indicates that the mitigation thresholds for NPCC, need to be reevaluated.

Market results also indicate that some of the parameters used to determine reserve requirements and threshold prices in the forward reserve market, and in the calculation of real-time reserve pricing, need to be reviewed after one year's experience.

Although participation in ISO's demand response program has increased, further improvement can be expected as the Region's experience with demand resources, and we have already implemented some of the changes as we found in the day-ahead load response program.

The market performance for the financial transmission rights, can be evaluated from two different perspectives: As a financial arbitrage instrument, the FTR market has performed competitively, but FTR does not offer a full hedge against the day-ahead transmission congestion costs.

And the ISO is working with the NEPOOL participants to develop the necessary changes and improvements in all these areas.

With the last two slides, I'd like to highlight two major industry changes, based on ISO New England's experience. First, strengthening the linkage between retail and wholesale markets, would allow individual consumers to respond to unbundled like light from a prison, prices in ways that benefit them most.

A primary benefit of current wholesale power markets, is that they produce competitive prices to provide compensation for a variety of distinct products and services. Consumers, however, can still see an aggregate price, and thus cannot respond appropriately to changes in the cost of the power to competitive prices that they receive.

Even though this can work to their advantage in terms of -- demand response to competitive prices, would provide valuable feedback to guide bilateral contracts, resource procurement, and investment.

Clearly, broad stakeholder involvement will be required to make progress in addressing this issue. The ISO can offer the price transparency necessary, but this information -- how this information is translated into consumers in ways that do not expose them to unwarranted price volatility or price shocks, is a matter that requires careful deliberation among all stakeholders.

Another major challenge, based on New England's experience, is to improve price formation during shortages or known as scarcity pricing. Considerable progress has already been made through real-time reserve pricing that has resources dispatched in the least-cost manner, to meet their either the system's energy or reserve requirements.

Further progress could be realized through full participation and integration of demand resources, so that they could also set prices during shortages.

Finally, transmission constraint management could be improved by adopting transmission reserve demand curve pricing transmission constraints during shortage conditions in the fashion similar to real-time reserve pricing.

This concludes my presentation. Thank you.

CHAIRMAN KELLIHER: Thank you very much, thank you for those presentations. We appreciate it.

Now, let's turn to the Empire State, and I'd like to recognize Karen Antion, the Interim Chief Executive Officer of the New York ISO.

And the new Chief Executive Officer is here today. Steve, can you stand up for a minute? I want to congratulate you for your assumption of that role. Congratulations.

And Karen is joined by David Patton, the President of Potomac Economics, the Market Monitor. So, New York, go ahead.

(Slides.)

MS. ANTION: Good morning, Chairman Kelliher and Commissioners. Thank you for this opportunity to speak with you on behalf of the New York Independent System Operator.

My goal today is to present an overview of how and why the New York ISO was established, and to describe the progress we've made toward enhancing reliability, securing adequate supply, and promoting market efficiency.

I will also discuss the challenges we anticipate and the steps we are taking with our market participants and regulators to address those challenges. Dr. Patton, the New York ISO's Independent Market Advisor, will discuss the highlights of his most recent assessment of the New York ISO's wholesale electric markets.

Neither the federal nor state government mandated formation of the New York ISO. In a proceeding conducted by the New York Public Service Commission, our stakeholders reached a consensus to establish a wholesale electricity Market Administrator and Independent System Operator for the state's bulk power system.

New York stakeholders decided to base the state's electric markets, on locational marginal pricing that would promote competition, improve efficiency, and transfer the risk of owning generation, from consumers to investors.

Similarly, FERC's Order 888 didn't mandate separation of power plants from transmission. Nevertheless, New York opted for divestiture of generation by the investor-owned utilities. This unbundling has helped ensure a level playing field, particularly among suppliers who can compete on equal footing to develop and operate New York's generation fleet.

The member systems of the New York Power Pool, in response to Order 888, filed to establish the New York ISO in 1997. On December 1st, 1999, we went live with a full spectrum of competitive wholesale markets.

Our stakeholders expected the NYISO to provide nondiscriminatory grid access for generation, provide accurate price signals and transparency, prevent abuses of market power, and maintain or enhance system reliability. That is what we have done.

From its inception, the New York ISO has implemented perhaps the most sophisticated electricity markets in the United States, in which market participants buy and sell approximately a dozen different wholesale electricity products.

Further, the New York ISO's day-ahead and real-time markets, are fully co-optimized across energy, operating reserves, and regulation.

In implementing the New York market structure, we have been able to provide prices that reflect the value of electricity at over 300 locations on the network, commit the lowest total cost resources to meet demand each day, while maintaining system reliability, and maintain resource adequacy to match system electricity demands.

The New York ISO's markets have grown in size and sophistication and today include platforms for demand response and virtual trading of energy, as well as generation.

The New York ISO's locational-based market price signals, are transparent and provide important information about when and where to invest in new resources. To ensure accurate market signals, we have also incorporated scarcity pricing concepts.

Restructuring in New York, has allowed us to maintain system reliability and permit customers to enjoy higher value from existing resources. New York State consumers have benefitted from the improved availability of power plants, especially nuclear power plants.

This is largely due to significantly improved plant availability. In fact, the New York State Reliability Council has concluded that the installed reserve margin for New York, could safely be reduced from 18 percent at the New York ISO's inception, to 15 percent today.

That is the rough equivalent of over a thousand megawatts of generating capacity that consumers did not have to purchase in order to meet reliability standards.

The markets in New York have also attracted new investment. Since the New York ISO's inception, over 6,000 megawatts of generation have been built, and almost all of that generation is in the locations where it is most needed.

Moreover, two new merchant transmission lines that can carry 900 megawatts, now connect southeastern New York to its neighbors to the north and to the south.

The New York ISO's competitive markets have provided nondiscriminatory grid access and encouraged development of renewable resources. Quoting from a letter to the Commission by the American Wind Energy Association, of last year, "Well structured regional wholesale electricity markets, operated independently, allow for greater amounts of renewable energy and demand-response resources to be integrated into the nation's electric grid."

According to NAWEA, 73 percent of installed wind capacity, is located in independently-administered markets that have only 44 percent of the potential for wind power generation.

Of the over 23,000 megawatts of proposed generation in the New York ISO's interconnection queue, just under 8,000 megawatts are wind resources.

New York's restructuring has benefitted the state by enabling the growth of demand response mechanisms. In the hot summer of 2006, the New York ISO recorded a new peak of almost 34,000 megawatts on August 2nd. Its demand response programs delivered the equivalent of over a thousand megawatts of power that did not have to be produced by power plants.

Thus, in periods of extreme system stress, New York ISO demand response programs have demonstrated their value in maintaining an uninterrupted supply of electricity. Indeed, the New York ISO's comprehensive reliability planning process, considers demand response, along with generation and transmission solutions, to meet reliability criteria.

Prior to divestiture, New York's generation was owned by a limited number of investor-owned utilities, essentially regulated monopolies.

While the purchasers' ownership of these assets remains concentrated, New York has effectively reduced the risks of market power through its robust market monitoring and mitigation program.

We have also taken the necessary steps to identify and address potential market manipulation.

In a time when we are experiencing a global credit crisis, it is important to say a few words about the New York ISO's credit policies. New York ISO stakeholders transact approximately $10 billion in electricity trades annually, yet we have minimized defaults without creating undue barriers to entry, through a regular process of refining our credit and collateral requirements.

We believe that there have been fiscal benefits to New York consumers, through New York ISO's operations, even though sharply increasing fuel prices have had a profound influence on the cost of electricity.

In an attempt to determine the costs and benefits of restructuring in New York State, the New York ISO retained the Analysis Group to study the issue.

The Analysis Group's March 2007 report, concluded the following: One, significant benefits have resulted from the impacts of New York ISO operations and market incentives; two, the systemwide benefits exceeded the New York ISO's operating costs in every year from 2000 through 2006; and, three, in the latter years, the difference is hundreds of millions of dollars, or roughly five percent of systemwide production and fixed O&M costs.

Based on information contained in a 2006 study by Harvey, McConaughy & Pope, for PJM, the Analysis Group concluded that savings to New York consumers, were approximately $100 million to $200 million annually.

Over the past nine years, the New York ISO has built a strong foundation for the future, but we will continue to face many challenges. These challenges include: Integrating sizeable amounts of renewable resources and developing the necessary transmission facilities to deliver output from these assets;

Increasing fuel diversity, while complying with increasingly stringent environmental regulations; fostering, interregional initiatives to conform market rules, so as to eliminate remaining seams and increase the scope of wholesale markets in the Northeast, thus optimizing the flow of power between control areas;

Examining the competitive market signals and incentives for developing infrastructure, whether transmission, demand response, or generation;

And, finally, developing market structures that will be a catalyst for introducing and expanding new technologies such as the widespread use of hybrid plug-in vehicles and energy storage, communications, and smart grid technologies.

The New York ISO and its market participants, have developed a comprehensive reliability planning process that has effectively met the state's reliability requirements, without having to resort to regulatory backstop solutions.

We are all aware of the challenges of siting transmission. New York State has not yet seen the major transmission buildouts experienced by our neighbors, because new natural gas plants have been located near the load centers in southeastern New York.

That has postponed the need for transmission expansion within New York State, but the situation cannot continue indefinitely. Additional transmission will surely be required in the future, to ensure the security of supply, provide fuel diversity, and mitigate the sharply increasing costs of electricity.

Generation from wind and other renewable resources, is limited to specific locations, and the siting of nuclear or clean coal power plants, is far less flexible than it is for natural gas facilities. It is our clear intent to move forward to implement a market-driven, transparent process for economic transmission planning, pursuant to the principles established by the Commission in Order 890.

Consistent with our prior efforts, we will work collaboratively with our stakeholders to develop a consensus filing on this important issue.

We recognize that one of the ways we can impact cost, is by increasing the efficiency of contiguous markets. Together with PJM, we have initiated a dialogue intended to produce a mutually-agreeable plan to eliminate cross-border barriers to trade, address cost allocation issues between ISOs, and improve the overall efficiency of the Northeast markets.

We will shortly expand our efforts to include ISO New England, Ontario, Quebec, and the Maritimes.

We believe that this should be undertaken in a comprehensive manner that includes market rules to support the interchange of power, and facilitate the allocation of costs for future projects to those who benefit across multiple organized markets.

The New York ISO will reinvigorate its efforts with its neighbors to implement joint congestion management and increase the efficiency of cross-border interchanges. Other initiatives include establishing a common data exchange protocol for the markets, supporting market participants' ability to hedge congestion across control area boundaries, implementing faster and more accurate settlements across markets, and building support for robust energy futures markets.

The formation of a State Energy Planning Board by New York State Governor Patterson, is a positive development for the State. New York has lacked a comprehensive energy plan since 2002, but now intends to release a draft State Energy Plan in March of 2009.

The New York ISO is committed to lending its industry expertise and technical support to this effort. Organized markets operating with transparent price signals and nondiscriminatory access, are well positioned to support government's energy policy objectives, such as reducing greenhouse gas emissions or achieving renewable portfolio standards.

Policymakers in New York have moved aggressively to deal with environmental issues, and we concur that these issues require attention. But we must also note that the environmental benefits that we wish to achieve, have the potential to increase the price of energy.

A further concern is that, absent a comprehensive national policy, New York may not fully achieve its stated goals.

We believe that the industry should investigate and encourage new technologies and use more efficient, cleaner ways to generate electricity.

We are encouraged by the resurgence of interest in constructing advanced nuclear power plants and developing clean coal technologies, the latter recently endorsed by New York's Governor.

Finally, it is essential that we redouble our efforts to promote economic efficiencies through further market evolution.

The New York ISO conducts ongoing strategic planning initiatives and has developed a comprehensive market evolution plan. Our end state vision is for competitive, liquid markets, wit the ability to hedge positions in both energy and capacity markets; additional opportunities for merchant transmission, demand-side response and distributed energy alternatives, fair and effective credit policies, and interregional coordination of day-ahead and real-time markets.

It is clear that significant work remains to be done. The good news is that we have made meaningful progress since our inception in 1999, to develop efficient, competitive markets, maintain the highest standards of reliability, and plan for the future.

We have furthered the competitive agenda formulated by federal and state policymakers.

As we enter a new era of policymaking on energy and climate change, the market structures we have created for wholesale electricity, can be the platform to further policies such as integrating green and renewable resources, reducing emissions, and moving vehicles from the pump to the plug.

There is no question that we face difficult challenges for the foreseeable future. You cannot pick up a newspaper or turn on the television, without confronting predictions about rising oil prices, economic downturns, and environmental disasters.

The other side of the story is all too often lost in the bad news. We choose to come down on the side of optimism, believing that problems can be solved with commitment to a clear vision, human ingenuity, and advanced technology. We are ready to play our part in the solution.

Thank you. I look forward to your questions, and I'll turn it over to David Patton, who will give the state of the market report.

CHAIRMAN KELLIHER: Thank you. David?

(Slides.)

MR. PATTON: Good morning. I appreciate the opportunity to speak, Mr. Chairman and Commissioners.

Just to clarify my role, I'm the Independent Market Advisor, which means that we're the external component of the market monitoring function. New York also has an Independent Market Monitoring Unit led by Nicole Bouchez, who is actually here today.

We produce the State of the Market Report, and I'm going to be giving a brief overview of the Report, if that's possible, and hopefully leaving time for questions.

So the -- first, just by way background -- and I think this was covered pretty effectively, but to give some specifics, it's my belief that the New York ISO operates the most complete set of markets in the U.S. And what does "completeness" mean?

This is a continuing challenge, to try to make the markets as complete as possible. Completeness really means establishing markets that are as fully consistent with the reliability needs of the system as possible, and when you do that, the market prices and the schedules and outcomes of the market, satisfy your reliability needs and it minimizes the need to do things in the short term, like having operators take manual actions and make side payments, which we call uplift, or, in the long term, to have to turn to things like reliability agreements to keep resources that are needed for reliability, on the system, because the markets are not providing the signal that will naturally keep them on the system.

It's not an easy task, because just the nature of electricity and transmission operations, is such that the reliability needs are often fairly complicated, and it's been a continuing evolution to establish markets that do reflect those requirements as completely as possible.

And it's one of the reasons why the New York ISO has never had to sign reliability agreements with its generators, is that it started back in 2000 with markets that had locational reserve requirements, capacity markets that had locational requirements.

I think they were the first ISO in the country to have that and to co-optimize their reserves, regulation, and energy markets, which is critical, because, on a five-minute basis, reallocates resources between providing reserves and providing energy and regulation.

The outcomes of those markets, the day-ahead and real-time energy and operating reserve markets, are transparent prices that reflect the value of energy at every location. And that has significant implications, both in the short term, where it helps coordinate the actions of participants in terms of dispatch, but it also sends the long-term signals you need to govern investment in new demand resources, supply resources, and it allows you to value economically, what additional transmission capability would be worth and greatly instructs the planning process.

The second thing is that the day-ahead market, plays a critical role in coordinating the starting of resources on a daily basis. In reports where we study markets that don't have a day-ahead market, we've seen vast quantities of over-commitment, which are really costs that are wastefully incurred by utilities who have an obligation to start generators to serve their own load.

When you have a day-ahead market, it coordinates that, and it also ensures that the lowest-cost resources are committed.

Lastly, it coordinates the delivery of the lowest-cost energy to consumers, given the limits of the transmission network. While in an integrated utility's control area, that coordination is relatively good, on a regional basis, outside of the coordinated market areas, transmission is not nearly as well utilized, because there's limited ability to coordinate the flows when power is transacted from control area to control area.

The five-minute dispatch, gives you a high degree of control over the flows over specific transmission lines. It allows you to operate them closer to their limits, and it improves reliability, because, as the flow approaches the limit, the generators will be redispatched continuously to manage that flow.

The TLR processes that are relied on in other areas, provide fairly uncertain relief, and that relief occurs with a great deal of lag, so it improves not only economics, but significantly improves reliability.

Capacity markets complement the short-term markets by providing signals that govern investment decisions, and help ensure that you have adequate supply and demand resources, and also the signals that you need to maintain the existing resources. It's not all about investing in new resources.

Lastly, markets for transmission rights are critical, because they allow participants to hedge the costs of congestion on the network.

At the broadest possible level, these are the conclusions of the State of the Market Report: We've concluded that the markets performed competitively in 2007, and that conclusion is based on our evaluation of participant conduct.

We found very little evidence of withholding, ether physical withholding or economic withholding to increase energy prices, ancillary service prices, or uplift in 2007.

This is, I think, particularly remarkable, because New York happens to have one of the least competitive areas in the country, which is called New York City. The transmission system, you just don't even want to try to understand the transmission system inside New York City.

I mean, first, they've got these old oil-filled cables coming into the City, that are -- I don't know where else they exist in the world.

But then they have a very unique system within the City, that creates load pockets where there's very little competition in these individual load pockets, and yet the conduct and impact mitigation framework allows outcomes to emerge in New York City, that are indistinguishable from a competitive market.

And mitigation is not very frequent. Mitigation happens, I think, less than five percent of the time in New York City, so it certainly exceeded my expectations in terms of how effective that mitigation structure can be, while limiting its intervention in the market, which has costs.

However, there is one competitive issue that has occurred in the New York ISO markets, and that in the ICAP market in New York City, which, for the same reason I suggested the short-term markets lack competitiveness, the ICAP market has also had issues, but the steps that have been taken recently, I think, should effectively address those issues.

Energy prices, overall, rose from six to 12 percent in most areas. It's driven almost entirely by fuel prices.

Natural gas prices increased by 15 percent in 2007, and natural gas and oil-fired generation, set prices in New York and in New England, and in a fairly high portion of the hours, so when the market is functioning competitively, the electricity prices will check changes in fuel prices.

This shows the all-in price for electricity in various locations. It shows the components of the all-in price that are attributable to ancillary services, energy, capacity, and uplift in four locations.

You can see that prices did rise in 2007. We show natural gas prices. They actually rose quite a bit less than natural gas prices in almost all areas, and they fell on Long Island. Part of the reason that they fell on Long Island, is that we -- is new merchant transmission from New Jersey into Long Island, 660 megawatts that contributed to relieving congestion, both into Long Island and New York City.

Although the Report shows that, overall, the energy markets have performed well, and we found no indications that fundamental changes are needed, the Report does include five recommendations, and I have tried to characterize them in three areas:

One is, we continue to believe there's a strong need to improve the coordination of imports and exports, particularly between New York and New England, because the efficient utilization of that interface, plays an important role in ensuring that the prices in both markets are efficient.

It's especially important when one or the other market is in a shortage and you would have otherwise have avoided a price spike, if you had fully utilized the interface.

Allowing participants to physically schedule between the areas, which is the status quo, makes -- is not likely to lead to full utilization of the interface, so we have a recommendation that the ISOs pursue a coordinated dispatch between the areas.

Secondly, establishing capacity requirements for Southeast New York outside of New York City, there's an emerging need for new resources in that area, and so that's an area where the capacity market requirements can be conformed t the reliability needs of the system to provide better signals.

Then, lastly, the remaining recommendations deal with various operational aspects of the market. But one overall conclusion that I think is important to state, is that our review of the price signals provided by the New York markets, are that the current markets are, with very limited exceptions, providing the economic signals needed to maintain adequate supplies, and that includes supply resources, demand resources, and transmission capability in New York. That concludes my presentation.

CHAIRMAN KELLIHER: Great. Thank you very much, David. Now we'll turn to PJM, and I'd like to recognize Terry Boston, the President and Chief Executive Officer of PJM Interconnection. He's accompanied by Joe Bowring, who is the Manager of the Market Monitoring Unit, currently the Manager of the Market Monitoring Unit of PJM.

And I just want to say that, depending on how your time splits, I want to accommodate Commissioner Wellinghoff. He's leaving at 11:30, I believe, so I may ask him -- I may interrupt Mr. Bowring or ask Jon to give his questions before you. No discourtesy is intended towards you. It's a courtesy towards Jon. So, with that caveat, why don't we start with Terry?

MR. BOSTON: As part of the teamwork that we have, I'm going to ask Joe to go first.

CHAIRMAN KELLIHER: I'm sorry, yes.

MR. BOWRING: Thank you for the opportunity to be here today. I will start with a brief review of some well-defined market metrics, and Terry will address the broader market metrics referenced by the Chairman earlier this morning.

Prices are obviously a key outcome of markets. Prices may reflect a variety of factors, from supply and demand conditions, including scarcity, input costs, or market power.

Prices in competitive markets, signal the value of resources to both suppliers making decisions about producing and investing, and consumers making short- and long-term consumption decisions.

Energy prices have risen, although not steadily, since the inception of PJM markets. As an example, although prices rose almost 16 percent in 2007, prices in 2007 were actually lower than prices in 2005.

The fundamental driver of energy prices in PJM, as elsewhere, has been fuel costs. Fuel costs make up 80 to 90 percent of the marginal cost of generation.

Costs of coal and natural gas are especially critical in PJM, as those fuels are marginal virtually 100 percent of the time and set price.

As an example, if fuel prices in 2007 were at the 1999 level, LMP, average LMP would have been $33.68, about $34, instead of the $61.66 that they actually were in 2007. That's a clear quantitative measure of the impact of fuel costs on LMP.

Substantial increases in fuel costs and energy prices, have continued into 2008. Forward curves of both coal and natural gas, indicate that prices are not likely to decrease in the foreseeable future.

Capacity prices declined substantially from 1999 through 2007, declining from over $50 per megawatt day to just north of $3 per megawatt day in the early part of 2007.

The introduction of RPM, resulted in substantially higher capacity prices. RPM prices are reflective of the actual cost to build new generation and to reinvest in existing generation.

Net revenue is a key measure of overall market performance, as well as a measure of market incentives, but higher prices do not necessarily translate into higher net revenues.

Net revenues, in fact, have been generally below replacement costs for all technology types since 1999, in PJM, although net revenues have increased substantially as a result of RPM, which addresses a fundamental gap in the market design.

High prices in energy and capacity markets, in the presence of high costs, do not mean there's a problem with markets. In fact, high prices reflecting high input costs, are evidence that markets are working well.

High prices in the presence of scarcity, also do not mean that markets are not working. In fact, again, they're evidence that markets are working well.

But high prices make it even more critical to ensure that prices reflect competitive outcomes. Competition uses the tool of regulation, requires clear and effective market power mitigation rules.

We have such rules in PJM. The most direct measure of competition, is, as Hong-po noted, markup. Actual prices in PJM are, in fact, set by units generating power at or very close to their marginal cost. That is, the markup is very low in PJM.

Based on that and a number of other metrics that we look at, we conclude that the results of the energy and capacity markets of PJM, continue to be competitive.

The Market Monitoring Unit will soon transition to an independent external company, Monitoring Analytic. The transition is going well, and we have a cooperative working relationship with PJM, and we are committed to ensuring that that cooperative relationship continues. Thank you.

CHAIRMAN KELLIHER: Thank you very much; that was very succinct. Terry?

MR. BOSTON: Good morning. I appreciate the opportunity to talk about PJM, its mission, and how we've delivered on that mission and how we plan to continue to do so in the future.

As the Commissioners have requested, I do plan to focus some today on the CO2 and how markets can solve the CO2 problem. We have submitted detailed comments.

My remarks this morning will be consistent with those comments, but I will try to hit the high points.

PJM has a distinguished history which has become especially pertinent to me in my new role, as I gain a better perspective about where we have been as an organization and why we are structured the way we are, and what we must do to serve the needs of our members, regulators, other stakeholders, and how the markets that we have created, serve the greater good of the economy.

PJM began with the recognition among three power companies, that pooling their resources and operating regionally, would improve reliability and lower costs for their customers. The year was 1927, long before the concept of an RTO was created here at FERC.

Their 80-year old idea is a legacy that is no longer as important, because we're seeing it nationwide, but when this was created, it was the foundation of our mission to ensure the safe, reliable, and secure bulk electric system, and create and operate robust, competitive, and nondiscriminatory power markets.

At the same time, we must understand our customer needs and deliver services in a cost-effective manner. I am pleased to report to the Commission, the fact that the cost of PJM to run it this year, will be the lowest in mils per kilowatt hour, since it was created to run a market in the late 1990s.

Today, I will address how PJM will continue to achieve its mission through operational excellence and by noting the benefits PJM is delivering in three areas: Reliability, fair and efficient markets, and infrastructure.

Operators can only play the cards they are dealt, therefore, they are very dependent on system planners. Reliability starts with getting iron on the ground, wire in the air, and demand-side resources in place.

PJM's formal planning process, the Regional Transmission Expansion Plan, RTEP, is examining a 15-year planning horizon for transmission needs, load growth, generation additions and retirements, congestion, and system constraints.

Through this process, major transmission projects have been approved by the PJM Board. To date, the PJM Board has authorized $10 billion, with a B, of transmission projects.

Along with the planning process, we examine new generation projects to determine whether or not upgrades to the transmission system are needed to ensure reliability.

Recently, PJM proposed revisions to its processes, that would expedite the review of new generation projects. As part of the Dominion settlement agreement, system impact studies for similarly affected projects, were reviewed as a cluster. PJM determined system upgrade required, by adding the entire group to the system, rather than looking at each project incrementally.

Recently this process, which saves time and money, had zero opposition from our members. I would say 100 percent support -- we did have some abstentions, but no one voted against this process.

If transmission generation and demand-side response are the legs of reliability, then competitive markets are the eyes. Market price signals to the RTO-administered markets are integral to improve system reliability. A competitive market uses clear, transparent information, such as locational marginal prices, to communicate grid conditions simultaneously with hundreds of market participants, pinpointing the real-time stressful conditions on the grid and making all of us partners in resolving reliability issues in the market.

It is still surprising to me how often this critical reliability component is lost in the debate around competitive wholesale markets. At the heart of the market operation is the real-time monitoring, the communication technology and the data to preserve reliability. PJM and other RTOs continue to drive advancement for the technology and processes used to monitor and manage the grid. As a matter of fact, some of our vendors are here in the room today.

For example, PJM's system operators use telemetering data for nearly 74,000 points on the grid to get a big picture view of the regional conditions and situations that could affect reliability, including those on neighboring systems. This broad field of vision helps PJM operators identify the operational problems very quickly. The market helps them solve the problems.

PJM also is working collaboratively to improve markets and reliability across even larger geographic regions. In our seams agreement perhaps the most prominent is the development of a joint operating agreement with Midwest ISO. If you could put up the slide, please, showing the joint agreement areas. It's in the presentation about midway through.

Much of the focus of these seams issues revolves around congestion management. PJM and the Midwest ISO have worked together to develop the NERC- and FERC-approved congestion management process. This application coordinates reciprocal flow gates to greater details and provides real-time data, and allows for real-time response between the two RTOs.

We are also working with other neighbors as well. PJM, the Midwest ISO and the Tennessee Valley Authority have established a tri-party joint reliability agreement to address several areas, including the need to address transmission loading relief procedures. I am pleased at Karen's testimony, and PJM is excited about the progress we are making with the ongoing discussions with the New York ISO, and I commented to Steve Whitley today that I would come to Albany very quickly to continue to work on those agreements.

(Slide.)

A critical part of what RTO competitive markets bring to the table is enhanced economic efficiency to benefit from the large RTOs. They manifest in a variety of ways all of our benefits, provide value for our end-use customers.

For example, availability of transmission and generation resources have increased considerably since the markets opened. Approximately 4 percent is the availability improvements that have made generation resources since we've opened the market. This increase in availability provides direct benefits by maximizing the use of existing resources. Retail customers also see major benefits from their electric distribution systems having joined an RTO.

The economic access to the broader wholesale market has directly resulted in generation production cost savings, plus higher utilization of lower-cost resources. For example, Dominion Resources reportedly saved $110 million in 14 months of their participation in the PJM market, based on fuel cost savings, rather than running their own generation resources.

The consulting firm LECG, in 2006, examined the effect of wholesale markets operated by PJM and the New York ISO. It concluded that these two markets have reduced average electric rates between $430 million and $1.3 billion a year.

To assure our markets are competitive, the market monitoring unit is continuing to provide PJM stakeholders and regulators critical analysis. We are working closely and cooperatively with the MMU on this transition to an external independent entity. I meet with Joe Bowring frequently, and I believe these efforts are going quite well. For the record, I want to ask Joe -- what do you think?

(Laughter.)

MR. BOWRING: I agree.

(Laughter.)

MR. BOSTON: I want to thank the Commission, and especially John Moot, for his dedication to resolving the issue on the market monitoring unit, and as we move this August to an independent market monitor.

Another success story on how markets are supporting reliability can be found in looking at the results of the May 2008 reliability pricing model auction for capacity. Although we will not discuss the first four auctions here today because of active FERC filings, the May

2008 auction for capacity for the operating years 2011 and 2012 signaled a significant change in how capacity is being procured. More than 4200 megawatts cleared the May auction, with more than a thousand megawatts of baseload -- one coal-fired unit, which surprised even me.

Just as important, this market supports demand-side resources and green power. A record amount of demand response -- 661 megawatts -- was bid into the auction, and the first solar generating plant was bid in and cleared the auction.

PJM is working with the states, and through the stakeholder process, to bring energy efficiency resources into the RPM capacity auctions. By the next auction we hope to have that in place, to have energy efficiency in that auction. This brings the promise of even greater demand participation in the capacity market.

The release of the Brattle report yesterday launches an important examination of RPM. PJM will use the stakeholder process for assessing and reviewing the report's finding, and we will ask the stakeholders and the state public service commissions for recommendations regarding RPM. It is an urgent and important issue that we get new capacity and demand-side resources in place.

I want to emphasize that everything is on the table in an open process to solve the capacity problem. In the meantime, PJM will continue to reach out to all interested parties to better understand their resource adequacy needs and issues.

Another way that PJM is fulfilling its mission is to develop tools to support our stakeholders and members, PJM helping the states facilitate their renewable portfolio standards through a renewable energy credit tracking system has created the generator attribute tracking system. It is an independent, centralized generation and emission database that enables states to implement energy policies for renewable energy and asks the generators to track through our databases the emissions that are reported at each generating station.

PJM markets are providing opportunities for innovation to solve current and future challenges in terms of renewable energy resources. The nameplate capacity of wind projects entering the interconnection queue is on a steep increase. Currently there are 1200 megawatts of nameplate wind and 20 facilities connected to the PJM grid. 1500 megawatts are under construction, and we have 38,000 megawatts of wind in the queue. You see why we're trying to solve the queue issue at PJM.

We are working to increase demand response and energy efficiency programs as a means to help hedge higher fuel costs that we've talked about today, and reducing the overall capacity needs in RPM and as a hedge against the cost of future environmental policies such as CO_2. Markets are the best approach to foster innovation and reduce the costs of implementing a climate change policy.

Commissioner Wellinghoff's question: on the demand side today we have considerable commitments. There's 4898 sites with 2944 megawatts registered in our economic load response program. When it went up to 98 degrees here in Washington D.C. early last month, 800 megawatts of that was self-propelled.

There are 705 sites totalling 3144 megawatts registered to participate in our emergency load response programs. This rapid growth of demand-side resources, along with the other accomplishments, reinforces that we are trying to stay on course in fulfilling our promise of reliability. Reliability will continue to be paramount, Job One.

Alongside that, the commitment to administer efficient, fair and transparent wholesale markets and encourage infrastructure, including demand-side response for future economic growth, in addition to how FERC and our tariff have defined PJM's role, we see ourselves as problem-solvers, particularly in facing the challenges ahead. And we'll continue to support our members in improving the generation interconnection queue. It will not be a good thing if we're short of generation because we have not performed the analytical studies. We will use the tools and technology and data we have to assess the impact of possible CO2 legislation and other emissions controls for our members.

There is no shortage of issues to build with. The United States will continue to face the impact of high fuel costs, and the increasing cost of new plant construction driven by worldwide competition for resources. We will continue to be challenged by the siting of both generation and transmission, and meeting the load growth throughout our region.

As Chairman Kelliher stated, environmental and energy policies are becoming integrated. We see the likelihood of climate change legislation and the potential of carbon cap and trade structure developing, and we are examining that impact to determine how we can help our members.

One area that bothers me most is, we really haven't studied the impact of the change in flows that CO2 could have on the grid. Right now, the prevailing flows are from the midwest to the southeast, and from the midwest to the east coast. Under a CO2 cap and trade, we may see reversing of those flows. That needs to be addressed.

In addressing those issues, PJM has recently run simulation models to estimate the emissions avoided due to the improvements in capacity factors. Results show the amount of CO_2 emissions avoided to be approximately 27 million tons per year. As a side benefit, the LMP reductions were about 10 percent, meaning the cost of avoiding CO_2 emissions from improved nuclear performance in a competitive market had a negative impact on consumer costs.

Unfortunately, going forward, there are few if any low-cost means for our industry to achieve the stringent carbon targets that are likely to be legislated. With PJM's generating mix so dependent on coal units operating at high capacity factor -- as a matter of fact, coal sets the market clearing price 70 percent of the time in PJM -- the potential of switching from coal to natural gas will prove to be expensive.

The short-term outlook for CO_2 reduction at low price is at best limited. But a competitive market for CO_2 is the best way to find innovative, economic solutions.

The PJM market will address climate challenge as well as the high cost of fuel in part by increasing the amount of renewable energy and demand-side resources we have available. Going forward, advanced technology will open new frontiers for the grid in many ways. Technology such as phaser measurement units will improve reliability in LMP calculations. Smart meters and electrification of transportation will enable opportunities such as smart appliances and plug-in hybrid vehicles. These devices will increase the off-peak utilization of the assets of the power system. Thus they provide economic efficiency.

Commissioner Spitzer, I was glad to hear that Commissioner Wellinghoff has a new evangelist on plug-in hybrid vehicles here today.

In conclusion, I believe we have a firm foundation for a fully-integrated operation and market construct that's flexible enough to embrace change, but resilient enough to stand for the core elements of a regional transmission organization: independence, transparency, the openness and fair treatment of our constituents. Nonetheless, in the final analysis, we have come to realize, as far as we have come, as much as we have achieved, our journey to a perfect market is far from over. In fact, we are here today despite what differences we may have or what shortcomings we may have.

RTOs are probably united in trying to do the right thing; to make this vital, important competitive market construct realize its full potential. At the same time, we have built an organization that has much to share, much to offer, and helps the problem facing our industry and our nation.

Reflecting on the 80 years of PJM history, I firmly believe our future, despite the challenges we face today, offers the same opportunity to make a difference. With your help and guidance, we will work hard to do just that.

Thank you. I look forward to your questions.

CHAIRMAN KELLIHER: Why don't we go with ten-minute rounds? Anna, you be the enforcer.

(Laughter.)

CHAIRMAN KELLIHER: Why don't we start with Jon.

COMMISSIONER WELLINGHOFF: In the context, I believe the electrification of transportation will give us the greatest opportunity we have to solve our energy problems, but at the same time it is a huge challenge.

Of course, most of you are aware that the Commission under Section 1223 of the 2005 EPAct has the responsibility from Congress to promote advanced transmission technologies, including energy storage. In that context, I read a report recently, although it was done a while back, that estimated that if more storage, for example, were put in the New York system, you could save somewhere between $500 million and $1 billion a year in the system if you had more storage.

I know PJM is working with the consortium, as Terry indicated, trying to integrate regulation services into the grid for plug-in hybrid electric vehicles. Most of you know I've been participating in a number of seminars and conferences where I've spoken to representatives of the auto industry, and I want to tell you there are huge misconceptions by the auto industry as to the operation of the grid and the potential for the grid and plug-in hybrid electric vehicles to integrate in a way that will benefit both the automobiles and the grid.

I think it's incumbent upon us to help alleviate some of those misconceptions. What I would like to do, hopefully, is call a meeting sometime this fall with representatives of the ISOs and also the auto manufacturers, to sit down and talk about some of these issues and see how we can work them out.

In that context, let me give you my three questions. First, please comment on how more storage can make grid operation more efficient and reduce costs, and how plug-in hybrids may provide that storage in part, and also how plug-in hybrids may participate and benefit from the competitive ancillary services regulations market.

MR. BOSTON: I'll start out.

I wrote my graduate thesis on the integration of Raccoon Mountain pump storage project into the TVA system. It was a 1530-megawatt pump storage project. It cost us $300 million to build, and its mark-to-market today is $1.6

billion. That gives you some idea of the difference of off-peak costs and on-peak costs.

The Wall Street Journal yesterday said, the pros and cons of nuclear power -- the pro was, it was the only alternative, was the first item. A combination of nuclear power and storage gives you off-peak load that you have to use, and plug-in hybrid vehicles I can see as distributed storage spread across the grid. And you can actually move the power into the areas at night, and it is at the end of the distribution system, at the end of the world.

So we have to be involved in the invertor-converter designs that the automobile industry would do. But it is very much what is needed. PJM, with the help of its members, will install a one-megawatt lithium ion battery on our campus very shortly. The key -- and we can commit to PJM's off-peak market -- can provide the equivalent cost of gasoline at 60 cents per gallon tonight.

So the economic efficiency is there. It's real. It's going to come. We do have to work with the automobile manufacturers, because how we design the charging systems -- if everyone comes home at 5:00 p.m. and plugs them in, we will have a major problem on our hands. So we have to have both controls and pricing signals to make that integration between electric transportation and the grid work.

MR. van WELIE: I think all the ISOs and RTOs will immediately like the idea of additional storage, particularly in the context of renewable resources like wind. There's clearly an opportunity, I think, to address the CO2 problem of the future if we can make these two resources work well together.

I see lots of challenges, though. I think the engineering side of it in some ways is easier to solve for than the other side of the equation, which is the investment required and the retail rate redesign that would be required. So this is not going to work unless you get the price signals through to the end consumer, and what we struggle with is that very topic.

A place like New England, particularly if you see our declining load factor, you would have thought that we would have gone there a long time ago. So it's a problem, and as we solve for the integration of demand resources on the system, and solve both the operational aspects of this as well as the price formation aspects of this, I think one of the byproducts we'll get is, we'll start solving for this issue as well.

MS. ANTION: I guess in general to respond to this, I look at it and say, utilizing the system more completely in every way is part of the solution, and of course spreading out the peak demand and being able to use the system in off-peak hours more efficiently has got to be part of the solution for us, both in terms of capacity and cost. There are some places, of course, on our continent where storage projects are being pursued aggressively. Our neighbors to the north, as an example, are building a very very large storage facility, and we've had some discussions and expect to continue that. We've had discussions about how we might use our markets together to take advantage of that situation.

Other than what's been said, I think that's my point.

COMMISSIONER WELLINGHOFF: Thank you, Mr. Chairman. That's all I have.

CHAIRMAN KELLIHER: Commissioner Moeller?

COMMISSIONER MOELLER: Thank you, Mr. Chairman.

A number of questions that I hope you can answer succinctly. The first one I'd like to ask of the three heads of the markets.

We get various descriptions of the communication abilities between markets, and how the cooperation goes. I guess I'd like your personal observations as to how you're getting along with your neighboring markets, and if there's a need for continued improvement there.

MR. van WELIE: I can't resist going first. We like our neighboring market so well that we sent them our chief operating officer.

(Laughter.)

MR. van WELIE: I look really forward to working with Steve, and of course we have a great working relationship with Karen as well. I was joking with her earlier on that you'll see a seamless relationship between New England and New York. Of course, I know Steve and Terry have worked together for many years, so I think it bodes well for the cooperation amongst these markets.

MS. ANTION: I would agree that change is an essential element of progress. The changes that we've seen in the leadership across the organizations in the region, I think, will prove helpful.

Particularly, the personalities and relationships that previously existed amongst these gentlemen aside, I think the value in their understanding the differences between our markets will prove helpful in terms of resolving the issues. You can't really fix what you don't understand, so there's I think a better understanding across the markets today about what are legitimately differences in the markets even where there are similar philosophies. They're structured differently, and that provides some challenges.

I think trying to eliminate what I'd call the barriers to trade, both by understanding what those problems are and then really pursuing aggressively what those differences are to broaden those regional markets -- I think the opportunity, while it has existed and while it has advanced heretofore, I think we're in a new era that will allow for a real growth spurt in that regard.

MR. BOSTON: Communication between the RTOs is quite good. The IRC met in Calgary and I think most, the majority of the board members and all the CEOs were there. We had open and honest discussions of how we're coming on capacity markets, the issues with the reliability standards and how we're working to assure that we are compliant with all the standards. We've had joint board meetings with some of the surrounding RTOs, and I might add that our discussions on seams agreement -- I'd like to say it this way. Our goal is a seamless market, not a seams agreement. Our goal is very clearly to have a seamless market.

COMMISSIONER MOELLER: Mr. van Welie?

MR. van WELIE: I'd like to just add something. I was obviously focused on the more lighthearted side of things in my earlier comments, but I'd like to just point out one serious issue, I think.

ISOs and RTOs are by their very nature regional organizations. Therefore, if they are to perform effectively, they need to pay attention to what the people in their regions want. That may not always be the same thing as what the people in the region next door want.

So there is an element of reality with respect to the fact that we have to solve for those differences that do exist. Sometimes they're political. And I think that's where your role comes in.

So I think where we'd be seeking guidance is, you know, where we proceed and on what basis we proceed on certain issues which, quite frankly, the ISOs and RTOs will not be able to solve on their own.

COMMISSIONER MOELLER: Well said, thank you. That's generally good news.

Specific to ISO New England, Dr. Chao, thank you for pointing out as you did -- the quote was, we need closer integration of the wholesale and retail markets. To me that's absolutely key, because of all the new technologies that I think we desire consumers get, whether they are plug-in hybrids or smart meters, they're dependent on retail consumers getting accurate price signals, something that most consumers don't get right now.

You mentioned a stakeholder process that -- Mr. van Welie, you mentioned a stakeholder process that is an attempt to solve this issue. Could you briefly describe what you plan to do there?

MR. van WELIE: Not a lot, actually, at a substantive level. We had this discussion in New England, and we got a very strong signal that retail rate design is not the ISO's business. I think what we will continue to do is to educate our stakeholders, be a resource to the states upon request, to weigh in on some of these issues. But ultimately the issue of how the states structure their retail rates is their decision.

So I think we have to wait for that evolution to take its natural course. I think price pressures will eventually get us there. Apart from being an information resource and making sure that our wholesale markets can work as well as they possibly can, and provide the opportunity for those who wish to participate in the wholesale markets to get access to those markets, I think that's our role. But I'd be happy to hear whether you think we're wrong on that.

COMMISSIONER MOELLER: Okay.

Last question for New England is related to the forward capacity market going out. There was some good news about prices coming in, but Mr. van Welie, can you kind of predict long-term -- are those prices going to be at the level that will attract sufficient generation? Any predictions on that, and the same to Dr. Chao if you have any thoughts.

MR. van WELIE: Well, we're optimistic at this point. I think we have to be prepared to see this play out, though. So that's going to be the big question, whether we can actually have the patience to watch things play out.

We will probably go into a bit of a surplus situation for awhile. Clearly, that will raise some concerns about new entry. I think that the mechanisms that exist within the forward capacity market, though, allow for the price to come up as people find themselves in a position of not being viable any longer.

The secret to all of this, I think, is having a robust transmission system. If our transmission system is not robust enough, we get ourselves trapped with RMR contracts, because that's the only resource that's available to us.

I think the other part of this is having robust demand response, because demand response can be a surrogate for the generator within the load pocket. I think if we can make sure our transmission system is robust, and have the patience, I think we'll see this play out over time. I am optimistic about it.

MR. CHAO: I share Gordon's optimism, but let me add one element here; market transparency, is what the wholesale market can really contribute to provide an environment attractive to new investment.

As I highlighted in one of the slides, we have observed that, over the period, although the wholesale prices are driven, to a great extent, by fuel prices, if we adjust for that, we found that in this market, overall in this period, it's a very complicated issue.

What is very striking, is that we have provide fairly stable wholesale prices, adjusted for fuel. We see that at this point, given this experience during the past few years, that it is justifiable to emphasize the transparency, to the extent that we can accomplish that on the demand side.

COMMISSIONER MOELLER: A question to New York and Mr. Patton: A year ago, I was concerned that New York City didn't have enough generation. You assured me that things were okay there, but I thought I heard in your presentation, a bit of a concern about the need for new generation.

Did I hear correctly?

MR. PATTON: No. If I gave you that impression, I may have misled you. We've built two new combined-cycle resources in New York City in the last year.

In fact, it's the fact that that created a fairly significant surplus and capacity prices did not fall to reflect the surplus, that caused the concerns about the competitiveness of the capacity market.

So, I think the only concern, I think, is ensuring that the markets provide competitive signals, so that when there is a surplus in an area like New York City, the prices fall and don't continue to send a signal for people to build, and that they're transparent, so that people can form expectations of where they will be, four or five years in the future, when we will need new capacity.

COMMISSIONER MOELLER: I'll continue to watch it. I want to highlight a success story that you both kind of touched on a little bit, anyway, and that is the Neptune Line.

Commissioner Spitzer and I went up in October. We showed up, we gave speeches, and we got the T-shirt, literally showing and proving that we were there.

But that has been a remarkable success for the consumers of Long Island. I'd like each of you to just briefly comment on that.

MR. PATTON: I think the most important thing is that it's a merchant transmission line. LMP markets, yes, there's this tension between planing and markets, because planners might say, we need to do something now, or here, and markets might not cause that to happen.

It's always been my belief that if you put transparent signals in that value incremental capacity, it's not just motivating generation; it will motivate transmission and transmission that doesn't need to be supported by a guaranteed regulatory rate recovery, transmission that investors are at the risk of.

The important thing in New York, is -- and it's important for demand response, too, is that you allow them to sell everything possible. For example, the Neptune Line can sell local capacity into the capacity market in Long Island.

It's not just used for transferring energy. If we didn't allow that, you'd be taking away one source of revenue from that project. Keeping an eye on those sorts of market issues, I think, can lead to more merchant transmission.

MS. ANTION: I would just echo that. It's private investment that has brought that incremental transmission to us. That is really the success.

As we said earlier, we're really focused on sending the market signals that will incent private investment in our infrastructure in New York, and both of those lines, additional lines, their private investment is the story that we like to tell, and we hope it will serve as a basis for others to look at.

As we've conducted our studies, we've got, like others around the table here, we've got a lot of wind energy that's in the queue, and it's our plan to do the studies that would put the information out, in addition to sending the economic signals, perhaps incent merchant transmission there, as well.

COMMISSIONER MOELLER: Thank you. I had a question for Mr. Boston, but I'm out of time.

CHAIRMAN KELLIHER: Thank you, Commissioner Moeller. Colleagues? Commissioner Spitzer?

COMMISSIONER SPITZER: Thank you, Mr. Chairman.

First, I guess, I have an observation on the plug-in discussion that Commissioner Wellinghoff started. There is admitted by the transportation sector, a lack of understanding of the electric industry. It's a difficult industry, particularly the regional nature, the balkanized nature of the transmission owners and the variations within regions within the country.

You have this chicken-and-egg argument or discussion of which comes first; the rollout of the automobiles, the technology and the attendant battery technology, or revisions to retail and wholesale designs to produce a rollout in scale to justify the change in factories from Detroit and the other manufacturers.

I've come to the conclusion that the electric industry is going to have to lead. That's going to have to precede this massive investment, potentially, by the automotive sector, so I'm pleased with the attention you've given to that.

Not only is the electric side going to have to lead, but the ISOs and RTOs within the electric industry, are going to lead the vertically-integrated sectors, as well as the retail electric sector. That leadership is going to be very important, going forward.

I want to follow up on the transmission issue. I was pleased that Commissioner Moeller discussed the Neptune success story. It seems to me to be the default option.

The force of inertia is a very difficult task of siting transmission, to rely on proposals originating with the transmission owners. Of course, Neptune was a unique circumstance. It was an arbitrage opportunity, but that's not a bad thing.

Arbitrage can, in economic theory, eliminate idiosyncracies and benefits ratepayers, so you've got the non-rate-based opportunity in the West, both for financial purposes, as well as to overcome siting opposition.

You've had joint ownership between public- and investor-owned utilities. I direct this to the CEOs.

What opportunities are available in this very arduous transmission siting process of looking to new forms of transmission ownership? Obviously, you've got Neptune, but to broaden that to advance renewables and to look at public/private partnerships, what do you think needs to change, in order to have more of these proposals?

MR. van WELIE: Well, just talking from a New England perspective, the change in how one approaches transmission ownership, is really something that the ISO can't do much with, because the transmission owners, this is their business, and, also, they're the ones that have to look for making those kinds of partnerships.

I'm aware of the fact that those discussions have started within New England. Whether it needs to get a bit of a nudge from your perspective, I think is a judgment you will have to make.

Clearly, it's hard to have the transmission owners act together as a collective group, at times, given the fact that they are pulled in different directions by the forces within their own states. They are also for-profit businesses who need to maximize their own revenues, but they are in a complex situation.

We've heard the requests within New England for some time, by public power, for example, to have a bigger stake in the transmission system.

How you get there, I don't have the answer to. Clearly, there is a request on the table, and I would hope that the transmission owners would actually take that very seriously.

COMMISSIONER SPITZER: What if they don't?

MR. van WELIE: It's not that public power is without tools in New England. I think the approach policymakers within the state, and that helps stakeholders to some degree.

What I've noticed, is that some of the transmission owners have recognized that life might be a little easier on siting some of these transmission lines, if they actually have the support of public power.

I think we're going to see that played out with MMWEC and Northeast Public Power, as we do the Springfield upgrades in western Massachusetts.

I think it's happening on an ad hoc basis, but I don't see any overall discussion occurring at this stage within New England.

COMMISSIONER SPITZER: Karen, you've heard ad hoc discussions. There is obviously concern with creating a formal structure that would incorporate a diverse set of potential transmission projects.

You've also heard the nudge. There's a difference between a push and a nudge. Maybe you could shed some light on that.

MS. ANTION: I guess there's a number of things happening in the industry. Perhaps in New York, at least, we observe our creating some impetus for action amongst our transmission owners.

The big umbrella called 890 planning, that gives us the opportunity to participate in transmission planning, I think has garnered the attention of those that, regardless of their positions prior, are now looking at transmission planning, perhaps through a new lens.

In New York, I think there are a myriad of opportunities in this regard. It seems that the most expedient way to increase the capacity of our system, would be to study building out the right-of-way that exists in place.

We have a number of opportunities, I think, within the overall system, to upgrade that system, where it would, in fact, perhaps find itself in the rate base.

Having said that, expanding that system to what would be the available right-of-way, I think, moves us in underneath that umbrella of economic planning.

So we'll put up our umbrella, we'll start our planning process, and I think it's our understanding that in New York, the transmission owners have started to have discussions about looking at the system more broadly and collectively in terms of upgrade to the in-kind level, and then perhaps to get into the economic planning process and look at transmission planning differently and more broadly.

But it's clear that we have the opportunity and the responsibility, honestly, if we're going to bring in some of these renewable resources. They're going to find themselves sited in places where transmission will be required, and, of course, it would be our desire and expectation, honestly, in New York, that we would try and do that in a way that will be compatible with the markets and that would incent private investment.

You raise an excellent point, Commissioner Spitzer, that those can take on a variety of forms. Public/private partnerships are not a new concept in other industries that have gone to a competitive market structure, and perhaps it's time that the P-3 Model has more vetting and full discussion here in the energy industry.

So I think those, all of those stars, are starting to align. I think that the 890 planning process in New York, certainly is going to be the umbrella under which we engage all the stakeholders in really proactive transmission planning.

MR. BOSTON: Let me commend the Commission for both 890 and the Energy Policy Act of 2005. They got it right in terms of the importance of integrating generation and transmission siting and planning, so that it is an integrated system.

We've had no problem with having public or private funds to develop transmission projects. The problem really is understanding the need and how much the economy is at risk, if we don't build new transmission.

So the siting issue is one that we have worked through. It's a very long process. It's very important that each individual state understands the importance of siting new transmission and its impact and the impact of not having the transmission, on the economy.

So we have to take a real hard look at that process. It is a very long process, and we need to try to find ways that we can understand how to develop it.

Part of it is using the existing rights-of-way, and a lot of the large projects that I have mentioned in the written comments that I provided to you, to a large extent, use the existing corridors and existing rights-of-way, just having to widen those rights-of-way, in order to increase voltage levels.

COMMISSIONER SPITZER: Okay.

MR. van WELIE: I'd like to add something. You mentioned different business models and I focused on the public power request to have some equity position in the transmission, but there's another issue, as well that I'd like to draw to your attention.

You know that we have an approach of socializing transmission investment for the purpose of reliability projects. There you've got a hard and fast reliability standard against which you can measure whether you're going to be in compliance or not.

I was hoping we could get there in terms of investment in economic transmission, in other words, transmission to try and do something about price volatility, to deal with some of the renewable requirements and regulatory requirements among the New England states.

I think it's unlikely. My observation at the moment, having been involved in this discussion for almost a year now, is that we're more likely to end up in a space which I would call elective upgrades.

Willing participants receive the benefits and start entering into multilateral agreements. That could be many transmission owners with many load-serving entities, with many resources on the other end.

And it may extend to be as broad as regional, but, clearly, at this point, I don't see the appetite within the region for proceeding down the same cost allocation route on economic transmission projects, as we have seen with reliability projects.

COMMISSIONER SPITZER: Which is a shame. At to me, the demarcation between economics and reliability, is often elusive.

MR. van WELIE: Eventually, an economic problem becomes a reliability problem, if leave it long enough, but the issue is, how long do you want to leave it and whether you can actually solve the problem through other resources, is part of the issue.

COMMISSIONER SPITZER: I'm out of time.

CHAIRMAN KELLIHER: Sorry.

(Laughter.)

CHAIRMAN KELLIHER: Commissioner Kelly?

COMMISSIONER KELLY: Thank you, Joe. First, an observation: We started out, or at least I started out with the remarks that today's elephant in the living room of the electric industry, is rising costs across the board -- fuel costs, materials costs for new infrastructure -- it seems to me, listening to your reports and your testimonies that your regional wholesale markets, are a real success story on this front, on keeping costs down.

In fact, my take-away from what you said, is that these markets have, indeed, kept costs down and actually have lowered energy costs from what they would have been, absent these markets.

I think that's a very important story to be telling today, and I'm glad that you're here to tell it.

Having done that, you've done it in a number of ways, by having good and efficient economic dispatch and by significantly increasing generator availability, as well as the point I think you made, Karen, quite well, that a lot of this has come from private investment that has not put concomitant risk on consumers.

So, I just want to make sure that that message is delivered.

The other three areas that I see us having a role to play in helping to keep costs of electricity down in the future, are in transmission, demand response, and technology for increasing efficiency.

Let me just ask you, and let me just lay out all my questions. Then I know we won't have enough time, but you can pick the ones that are most interest to you, in the time we have, to answer.

Transmission: Obviously, more robust transmission will keep electric costs down. Karen, you mentioned that New York has been spearheading interregional efforts in markets. I'm wondering, are you engaging in interregional efforts in transmission and transmission planning, in particular, to synchronize the transmission across your region, to keep costs down and to make the most efficient use of imports, exports, and transmission infrastructure?

Gordon, you mentioned -- you talked about the transmission projects that are being looked at, and the question you had, was whether they're economically viable? One followup question I have for you on that front, is, when you say "economically viable," are you talking about the actual cost, or are you talking about methods of allocation, which you hinted at in your response to Commissioner Spitzer's question?

"Economically viable," does it mean that the allocation method has to be right, too, so that the costs are shared?

Demand Response: Hung-po, you talked about one of the significant challenges that New England is looking at, is improving demand-response programs. I suspect that what you were talking about there, is improving the methods you have for setting baselines for monitoring and verifying.

My question to you, is, is that what you meant, and, if so, are the other regions working on or do you feel that your demand-response programs, are already up to snuff?

Finally, technology: Terry you mentioned that PJM has a Smart Grid Working Group, and, Karen, you said that New York is setting up groups to provide the proper incentives for technology advancement.

I want to ask specially about smart grids and preface my question with another observation. Commissioner Butler of New Jersey and I, are co-chairing a FERC/NARUC collaborative for which 21 states have signed up to participate in that collaborative.

They are very interested in smart grids. We had conversations with each of the Commissioners in the last two weeks, and a recurring theme was their interest in understanding better, what is happening at the transmission level, particularly through the RTOs and ISOs, on smart grid technology.

I wanted to ask you if -- I assume you're working on that -- would you be willing to provide a point person within your organizations, to be available to work with this collaborative and with state regulators to talk about smart grid efforts at the transmission level, and how the states might learn from the work you've done, and integrate their efforts with yours?

So that's the spectrum of my questions.

(Laughter.)

COMMISSIONER KELLY: I'll turn the microphone over to you all.

MS. ANTION: I guess I'll start. Let me start with the last question, first, if I may. In terms of smart grids, I think that the focus on smart grid technology -- and I appreciate, again, your having spoken at the symposium in New York, where this is an important issue.

We have already invested a tremendous amount of resources, financial resources, in smartening the transmission grid, the wholesale grid.

I know this is true of others. I'll speak about New York, but I know it's true of all of the ISOs/RTOs.

When these organizations were formed, there weren't markets, of course, when we were formed, and, historically, the investment in technology around the transmission system, by the utilities, was -- well, it was a matter of record, let's just say that.

I think when you say, let's have a competitive wholesale market and let's integrate that tightly with the grid, and let's have the grid be smart enough to be able to react in a real-time way, so that I can buy and sell the power and move it where I need to, on both a real-time and a day-ahead basis, there's an awful lot of moving parts there.

To get it right, at the level you're describing, it really involves both an initial investment in technology to support our market evolution, as well as to smarten up the grid.

When you look at it today, I think it's probably one of the best kept secrets about one of the results of competition, and that is that there has been a smartening of the grid at this particular level.

The question then is the one that Commissioner Moeller had, which is, how do we extend that now to consumers? I think we start by recognizing that those investments have been made, we have these markets, certainly in New York, that are, as you heard them described by our Advisor, is a real-time, day-ahead market with lots of products, lots of buying and selling by market participants, with virtual trading, as well, all that being translated to the grid where dispatch is done electronically, ramping is managed electronically, and the whole thing is modeled.

Really, the efficiencies that we're realizing, and the savings that we're having, and the reliability improvements that you're seeing, are, in part, a function of the technology investments that have been made.

First, let me say that we in New York, would be happy to appoint a point person to work on the collaborative and support the collaborative, because we think it's a really very important nationwide initiative.

Then, of course, we agree with the observation made earlier, that while we're in the wholesale business, if you look at any industry where competition has prevailed and that change has taken place, you really see the largest change, once the consumer is engaged.

So, real-time price signals down to consumers, is a natural byproduct of the work we're doing, and then we'll come back around, I think, to improve the wholesale markets and help us realize even greater efficiencies.

All of that's important. Yes, we'd certainly like to support the collaborative with a point person from New York.

Just one moment on interregional transmission planning: Yes, we have been doing that planning. Again, when I look at this, I think of it in terms of how the different regions -- again, obviously, PJM and New England have done a lot more buildout of their transmission system, for reasons we discussed earlier.

The question is, how then to extend appropriately, those transmission systems to places where the need might exist, whether it's in those two regions, or even in Canada, and how to do that in ways that are a function of market signals, perhaps, as opposed to just making a determination that, in fact, those investments need to be a function of some sort of a formulaic approach.

But, again, we're looking at that. That's the purpose of the discussions, is to make that determination.

Clearly, as long as we're talking about things, going forward, I think we're all aligned with beneficiaries paying, but it's a matter of who is paying and to what extent, and that is, of course, in all of those details, but we're working on that and expect that we'll have a lot more progress next time we talk about this particular subject.

CHAIRMAN KELLIHER: Thank you. Can PJM respond quickly, and New England respond quickly?

MR. BOSTON: Very quickly, the Smart Grid Initiative, much of that is focused at the distribution system, and I think it's very wise.

I've talked to Fred Butler about this. The states and FERC work together.

On the transmission side of the technology, there are three things we really need: Storage, that we talked about with respect to plug-in hybrid vehicles; we need controllability to AC, which is high-powered electronics, and we really need long-haul DC.

If you look worldwide, about 20 percent of the grid, worldwide, is high-voltage DC, with long transfer capabilities built into it. The PMU technology is probably the most dominant focused at the grid, coming out of the blackout.

It was said that phaser measurements with the ability to measure things at 30 samples per second, and every four seconds, with the help of DOE funding, that is well underway.

I'm chairing the North American Initiative for Phaser Measurement Units. I'll be glad to work with you and Fred and provide support for you. It's kind of like comparing x-rays to an MRI.

When you look at what we can see in real time with phaser measurement units, on the demand side, it's happening very quickly. Our biggest challenge at PJM, is having the metering and monitoring capability in place to assure that everyone is doing something to earn their value on the demand side.

We think it's a very small problem, but we had our Board approve a project to improve our billing systems around demand side. On the transmission planing, RTEP is well integrated with other systems to out south, and knowing that Steve Whitley is a transmission planner from days gone by, I think we will become well integrated to our north, very quickly.

CHAIRMAN KELLIHER: Thank you.

MR. van WELIE: To Commissioner Kelly's question, I think it's both actual cost allocation, and the two are related or interdependent. The actual cost issue, is what's your view on the price of gas for the next 20 years or 30 years, because you're looking at making an investment that's going to last 30 or 40 years and you want to make sure that it pays back.

So the question is, is gas going to come down from $12 per million Btu, back to $7, or is it going to go up to $20? If you knew the answer to that question, it makes the cost/benefit a lot easier.

In some ways, we're in a race between the price of steel and the price of gas.

The other problem is the annotation problem. I'll use an example that's been very much on my mind the last several months, which is the Maine Power Connection. This is a project that would branch off from that Maine Power Reliability Project, which is used for reliability purposes and interconnects 800 megawatts of wind up in northern Maine.

In the long run, given everything that we've seen in New England, it looks like a pretty sensible thing to do. It would be a good project.

Pretty much everybody I've talked to in the state of Maine, wants to build that project, from the Governor down. The problem is, we don't know whether it's economically viable at this point.

The question then becomes, how do you get such a project built in New England? Can you do it on a regionwide basis, in terms of the cost allocation, without attributing the comments?

Here are some of the comments that get made to me by stakeholders and policymakers in other states: How do I know this is the right project? Okay, is there not some better one around the corner?

There are three other proposals that I've heard about, and how do I make the decision about what the right project is? The other would be, well, I'm entering into long-term contracts to hedge my energy costs for the next 20 years.

I'm going to lock my prices in. Why do I want the additional cost of transmission, if I'm not getting any energy benefit?

Another example would be, well, by proactively socializing a transmission investment like that, you are removing my negotiating leverage with the resource owner.

These are all very good points. They are some of the issues we have to work through and solve for within the region, to see whether we're able to come up with a solution.

MR. CHAO: I'm wondering if I could take a brief moment to comment on the demand response question?

CHAIRMAN KELLIHER: Quickly, please.

MR. CHAO: From New England's experience, I just want to comment that we're getting into a growth in demand response in two dimensions -- depth and breadth. Depth is measured in terms of size, and we have experienced some challenges that Commissioner Kelly mentioned, and baseline is one of the fundamental issues.

We're also -- we see the breadth as consumers, the diversity of demand response is enormous, just like the diversity on the demand side.

Now, how to handle the breadth of demand-response programs, all the way from reliability of demand response, to energy efficiency, like peak load/base load, is a spectrum of incentive issues, all intertwined with the baseline determination.

That is what we see as a challenge, as we grow to rely on demand response to a much greater extent. Thank you.

COMMISSIONER KELLY: Thank you, thank you, Joe.

CHAIRMAN KELLIHER: I just have a few questions, but let me start off with a statement, though.

Karen at PJM, we discussed the dialogue you're agreeing to, as well as some of the Canadian authorities, to address cross-border barriers to trade and some of the challenges regarding cost allocation among or between RTOs and ISOs.

I just want to say that I think that dialogue is very important, and we hope those discussions are productive, and we'll be observing them.

If they prove to be unproductive, there's always the possibility of us providing some structure to the discussion, or at least the U.S. entities. I just want to wish you the best in your discussions.

(Laughter.)

CHAIRMAN KELLIHER: Secondly, I want to ask a question of the Market Monitors. Single-price auction versus pay-as-bid, some critics of RTOs are offended that low-cost generators in a single-price auction, earn greater profits than high-cost generators.

They seem to think that if we were to simply go to pay-as-bid, they seem to assume that bidding behavior remains unchanged. In a pay-as-bid scheme, a low-cost generator bids in marginal costs, and that, therefore, prices fall sharply.

To me, it seems irrational that a low-cost generator would bid in at marginal cost in a pay-as-bid auction scheme. But, hypothetically, do you think that if we did that, we could expect changes in prices? Would you expect prices would be the same, perhaps higher, perhaps lower?

MR. BOWRING: I think there's a long literature on this. The best case, if it worked perfectly, would be about as good as it is now. A much more likely case, is that prices would be higher, and it is absolutely unrealistic to expect that a low-cost generator would bid low in a pay-as-bid auction. It would be irrational.

In fact, what everyone seems to be doing, is trying to guess the clearing price. In fact, what it does, is, it makes monitoring impossible, because, really, there is no good benchmark for what competitive behavior is in that case.

So, I think, as I said, the economic literature is quite clear: If it worked perfectly, which it can't, it would do about as well as a single clearing price, and, in actual practice, it's much more likely to do worse and much more likely to end up with market power issues and with higher prices.

CHAIRMAN KELLIHER: Thank you. David?

MR. PATTON: In experimental economics, one of our Board members is a faculty member at Cornell, where they have done experiments on pay-as-bid.

When people say, if it works perfectly, you get the same outcome, it's not going to work perfectly. The person with the base load call unit, is going to guess that the price is going to be here, and it ends up a little bit lower, and you end up not running the coal unit and you run a bunch of gas units instead.

So when mistakes are made, because, of course, foresight is not perfect, it guarantees that costs will be higher.

CHAIRMAN KELLIHER: Do you agree?

MR. CHAO: I agree.

CHAIRMAN KELLIHER: Thank you for conserving my time.

(Laughter.)

CHAIRMAN KELLIHER: I have one other question, and this is something Mr. Bowring addressed. Higher prices do not necessarily translate into higher net revenues for generators, but there's a perception, a public perception, that with high electricity costs, that there's great profitability by the generators, and there seems to be a discounting of the importance of fuel prices, the impact of fuel costs in those higher prices.

But there's a perception that there's enormous profitability by all generators across the board, but some of your reports in the past, have indicated that wholesale prices haven't supported new entry, so there seems to be this disconnect between the perception of vast profitability, at least in some regions, but in reality, that new entry is not supported by the same prices that are deemed to be incredibly profitable.

Do current prices support new entry? In recent years, say, the past three years, have wholesale prices supported new entry?

MR. BOWRING: On the energy price side, energy prices have not, for the nine years of PJM's history, supported new entry, despite the fact that they have risen and fallen with fuel prices.

PJM, in particular, as Terry pointed out, coal is on the margin 70 percent of the time. At that point, there's no margin for a coal unit, let alone for a higher-priced unit, so when gas is on the margin, they receive higher net revenues than the gas unit on the margin, but, nonetheless, our detailed analyses show that that has not been adequate to support or cover the cost of new entry for any type of generation.

The only exception to that, was 2005, when we had a sharp run-up in natural gas prices. In fact, that did result in substantial inframarginal revenues for coal plants, that would have supported new entry in that one year.

That's really a significant part of the reason why we and other RTOs, have capacity markets, as well, because energy prices, by themselves, as they currently exist, do not and have not been adequate for new entry.

CHAIRMAN KELLIHER: Thank you. David?

MR. PATTON: I have the same basic story. Other than New York implementing its shortage pricing back in 2003, the first one to do the operating reserve demand curves, when you run into a shortage, you short your operating reserves and there's a reliability impact to that.

If you price that, you get much higher net revenues. Once you start running into more frequent shortages, that, combined with the capacity market, has tended to -- will support entry.

Now, the problem in New York is that we've had a surplus outside of New York City for the past four or five years, so the signals have been not supporting new entry, but it's not a market design issue; it's a surplus issue.

They have supported entry in New York City, where it had been tight.

MR. CHAO: A number of observations from New England: New England has not seen new iron in the ground for three years. During the FCA, the Forward Capacity Auction, we attracted very visible interest over the years.

We can attribute it to the development of a number of events; certainly the development of the capacity markets all the time, a resolution, and also the development of the reserve market, the forward reserve market and real-time reserve pricing, also provided a more complete market, and most recently, the forward reserve market, that price hit a price floor and with abundant supply.

So, when we put all of these together, another factor we see, is that the market has reached a point where future uncertainty has been reduced significantly. That's what I see as another factor that can be very attractive to investment, so we are optimistic.

MR. van WELIE: There is one Scenario Analysis that showed us something that was pretty soft. We sat and looked at the revenues that the resource could capture out of the energy market, and we looked at the capital costs of different resource types, looking forward, and there wasn't any resource, other than DR energy efficiency and combined-cycle gas, that could actually make a living on the combination of the energy and capacity markets, were it not for some other additional revenues on the side.

So, wind and that sort of thing, obviously gets federal tax subsidies, they can collect incentives from the state RPS standards, so the notion that there is this huge profit to be gained in the energy markets, is just wrong.

A lot of that is targeted at fully-depreciated assets. People who took the risks to buy the nuclear facilities when nobody else wanted them, and are now earning good revenues on those, I think that's part of where the discontent is coming from.

But to project that forward and say that there's some huge profit opportunity here, I think, is incorrect.

CHAIRMAN KELLIHER: To the extent we've seen lower levels of generation entry in recent years, that's a period where a new entrant really couldn't reasonably expect to recover their costs.

New England, in 2004 and 2005, I think you estimated that a new entrant could expect to recover 58 percent of their costs, so we didn't see a lot of new entries.

So, just as it's irrational to expect change in the auction scheme, under a pay-as-bid auction, it would be irrational for someone to bid in marginal cost at all, so it might be irrational for a generator to build with the certainty of losing money for a good period of time.

Okay, well, there is more than one way to support new generation. I think capacity markets are something we've approved, because they're promising and they are better than the old approach.

In Australia, they have a pure, energy-only market with a $10,000 cap. That is another approach, but I don't think that even the critics of RTO markets, would propose that.

I really thank you for your participation. I welcome you and the panelists in the afternoon session, to join us upstairs for lunch. Thank you for helping us.

(Whereupon, at 12:15 p.m., the Conference was recessed for luncheon, to be reconvened this same day at 1:00 p.m.)

AFTERNOON SESSION

(1:05 p.m.)

CHAIRMAN KELLIHER: We're going to resume the Conference with the great state of California, the New York of the West. Do you ever call yourselves that? No? Probably not.

(Laughter.)

MR. MANSOUR: Actually, they are the California of the East.

(Laughter.)

CHAIRMAN KELLIHER: I understand we're going to start with Keith Casey. Keith is the Director of the Department of Market Monitoring of the California Independent System Operator, and then we'll turn to Yakout Mansour, the President and Chief Executive Officer, and the Frank Wolak, the Chairman of the Market Surveillance Committee, will join in the discussion and the Q&A.

Why don't we start with Keith?

MR. CASEY: I have slides here.

(Slides.)

MR. CASEY: All right, well, good afternoon, Chairman Kelliher and fellow Commissioners. It's a pleasure to be here. We really appreciate the opportunity to offer our perspective on the state of wholesale electric competition.

I'm going through a slide presentation today, but in addition to that, we also have some prepared written comments. These are joint written comments by Dr. Wolak and myself.

Our presentation today, as well as our written comments, will focus primarily on the current state of the California market. Mr. Mansour will follow with comments focusing primarily on the challenges, going forward, and how electric markets will need to evolve, and the attributes they will need to have to meet those challenges.

In terms of the current state of the California market, our basic assessment is that the California market is stable and competitive, but it's not all that it should be.

Our analysis of market prices have shown that they have been within competitive ranges over the past six years, moreover, there have been a number of significant improvements in the market since the energy crisis, which I have listed here. I will be discussing each of these in a moment.

However, despite these improvements, the current market does suffer from some deficiencies; namely, there is currently no centralized day-ahead market and there is a lack of price transparency on the day-ahead basis.

Also, we do not currently have nodal pricing, therefore, a lot of the congestion that we deal with, has to be dealt with in real time, through out-of-merit-order dispatch, and there's a lot of socialization of the congestion costs, as well as a lack of price transparency.

Finally, there's no meaningful participation by final demand in our markets. Demand is pretty much what you see is what you get. The good news is, MRTU, our new market design that we'll be implementing this Fall, will fix the first of these two deficiencies, by providing a centralized day-ahead market and nodal pricing, and it will provide an excellent framework for demand response.

However, it will take some time to develop meaningful demand response. Having an ISO with a market framework, is an important first step, but, ultimately, the success of that effort, will require close collaboration with various state agencies in California.

The good news is that California has been working very diligently with those agencies, to develop more meaningful demand response.

In terms of the major improvements in the California markets, we believe the two most stabilizing changes since the crisis, have been the significant level of forward energy contracting by California's load-serving entities and the introduction of a resource adequacy framework.

In our view, the California energy crisis was primarily due to a lack of forward energy contracting, which both created opportunities for the exercise of market power, and created significant financial risks for load-serving entities.

Fortunately, today, or load-serving entities are largely hedged against spot market volatility, with fixed-price, long-term power contracts. That's been a tremendous stabilizing change.

More recently, in June of 2006, ISO implemented a resource adequacy framework that ensures sufficient capacity is committed to serve California load on both a year-ahead and month-ahead basis.

That structure continues to be refined over time, and the CPUC, in close collaboration with the California ISO, is looking at alternatives for a longer-term resource adequacy framework.

We believe many of the market improvements noted in the next few slides, are really being driven by these two fundamental changes in the California market.

One of the key metrics we use to measure market competitiveness, is a price/cost markup, and you've heard some of the monitors earlier today, talk about that, as well. Essentially, it measures the difference between actual market prices and our estimate of a competitive baseline price, based on marginal-cost bidding.

The chart I have up here currently, shows average monthly markups. They are shown in the blue columns, and it also shows a 12-month rolling average, which is the blue line. This is for the past five years.

In summary, in terms of the monthly markups, they are generally quite moderate. We do see some spikes during the peak summer months, but, more importantly, the 12-month rolling average of average price-to-cost markups, is extremely moderate, within the $3 to $6 range over this period.

The next slide shows average wholesale energy costs, and what we've seen here, is a significant decline in average wholesale costs, when you adjust for changes in fuel costs.

We show, actually, two values in this chart. The blue column shows the normalized wholesale cost, when you adjust for fuel price, and the red line shows the nominal cost.

What you see here, is, when adjusting for energy costs, the average wholesale costs have declined over this six-year period, and have really stabilized to around the $45 per megawatt hour mark.

This decline is primary driven by the influx of new generation that we've had over this period, as well as the expiration of a number of state contracts that were signed during the crisis.

Another positive trend is that grid improvements have significantly reduced reliability management costs. These costs are costs the ISO incurs to manage local reliability issues in real time. They include such things as out-of-merit dispatch; unit commitment, RMR dispatches, and what you see in this chart, is that over this four-year period, these costs have declined by 75 percent, from approximately $400 million in 2004, to roughly $100 million in 2007.

I should point out that the Department of Market Monitoring has its own method for measuring reliability management costs, which is slightly different than something that the ISO itself tracks as part of its corporate metric, so you may have heard numbers of reliability management costs, going from $1 billion to $200 million.

It's the same general type of cost; it's just calculated slightly differently, so I just wanted to offer that distinction.

We've had a significant amount of new generation built over the past seven years. This chart has a lot on here, but if you focus on the blue shaded area, what it shows, is the amount of generation additions that we've had, systemwide, which is approximately 15,000 megawatts.

This is from 2001 to 2007. That helped to facilitate about 5,500 megawatts of generation retirements, and when you add on top of that, an approximate load growth of about 6,500 megawatts, the net change in generation, systemwide, is about 5,500.

The tables directly above that, show how those numbers break out between southern and northern California, and what you can see there, is the new generation development is almost exactly the same in both these regions, but we've had a higher rate of retirements in southern California, so the net gain is predominantly in northern California.

I'll quickly go through these slides. One of the things we track, is the level of average annual forced outage for our generation fleet, and you see here, a chart for 2000 through 2007, showing very favorable declines in forced outage rates, where, in 2007, the forced outage rate was the lowest in seven years.

Similarly, we also track the utilization of older, less efficient generation, and here again, for 2002 through 2007, you see a continued decline in the percent of hours that older generation is operating. And in 2007, it was operating in just 26 percent of the run hours.

You heard a lot of discussion in this morning's panel about revenue adequacy. That is something we track, and this last chart I have here, is not really showing achievement, but an observation, consistent with what Joe Bowring noted about PJM, which is that consistently, our estimate of net market revenues for new generation, is below the levelized annual cost of new generation, and that really underscores the critical importance of long-term contracting to help bridge that gap and facilitate new investment.

So, to summarize, the California market has been stable and competitive since the crisis. We've seen significant market improvements, but, as we've noted, we do have some deficiencies -- the lack of a centralized day-ahead market, the lack of nodal pricing, and limited demand participation.

MRTU will address the first of these two deficiencies, and certainly provide a better framework for demand participation, but getting greater demand participation in our markets, will require much more work and close collaboration with the state agencies.

I'm happy to report that the ISO's very vigilantly involved in working with the state agencies to bring that about.

I did want to note, while I'm the topic of MRTU, that while the MRTU systems and markets are being thoroughly tested before being deployed, issues may nonetheless surface, after these markets go live.

I did want to assure this Commission that we will, as the Market Monitoring Unit, have the capabilities in place to quickly detect market problems and work with the ISO to develop rapid solutions or at least effective solutions.

And to the extent a solution requires quick action from this Commission, we hope that you and your staff will be equally engaged in following the performance of MRTU, after it goes live, and be prepared to give expedited consideration, if warranted, should issues arise that we may need to bring before you.

So, with that, I will turn it over to Mr. Mansour, to talk about some of the future challenges, and the ISO's perspective on how the markets will need to evolve to meet those.

(Slides.)

MR. MANSOUR: Thank you, Mr. Chairman and Commissioners, for taking the initiative and the time to listen and to speak to all of us on where electricity market reform stands and where it is heading.

Like you, we all see the number and frequency of reports that largely misrepresent the state of the market. If we try to read, understand, and analyze even the first page of every one of them, I don't think we'll have any time to do anything else.

So, for you to give us the opportunity to give you the whole story and to tell our whole story in one day, that's a very efficient way of doing it. That's almost as efficient as the RTO systems.

(Laughter.)

MR. MANSOUR: And in addition to what Mr. Casey presented, I will focus on the transition to the challenging future.

In a nutshell, California is well past the 2000 and 2001 crisis and has made tremendous progress on several fronts. I can tell you what it is, and Mr. Casey told you what it is, and I heard the question in the morning from Commissioner Moeller, saying how do the consumers understand what it is?

We can also analyze, based on surveys and whatever, but the most compelling story is that late in 2005, there was a proposition on the ballot to try to undo some of the restructuring in California.

That proposition was defeated by a margin of 2:1, so the people had their say; they don't want to go back to the old system, in part or in full.

Yet we remain distant from long-term future goals, because the ideal goalposts are continually moving. In my brief address, I will speak briefly to each, our progress since 2001, current efforts to address California's environmental objectives, and a vision for reaching those ideal goalposts.

As my colleague, Dr. Casey, mentioned, California has made great progress since 2001. He mentioned correctly that the net generation addition outpaced load growth, after retirement, by about 5,000 megawatts.

To put things in context, that net is more than the entire additions of generation facilities in the 1990s, before restructuring. I was looking at the date and the average addition of generation in the 1990s, with about 360 megawatts a year.

We're talking about net addition, after growth and after retirement, of 5,000 megawatts since the crisis.

Average wholesale energy costs, when normalized, for 2004 fuel costs, is the lowest since restructuring. Reliability of the generation fleet is higher than ever, and, frankly, every year, exceeds my most imagination.

Last year, we reached a forced outage rate of generation from the generation fleet, below three percent, and, actually, it was close to two percent.

Reliability costs dropped to 75 percent over the last three years. Operators actually managed a record peak demand, six years ahead of forecast, without forcing any customer interruptions in 2006.

The value of the transmission investment, between what is already in the ground, what is under construction, and what is well into the state process, is over $8 billion since the initiation of the ISO.

Today, the electricity industry faces major new challenges that are driving a transformation in how our industry will meet future electricity needs. Independent operators are especially well positioned to address these challenges, many of which are already arising in California.

In my state, policymakers are addressing a collection of environmental initiatives with direct and profound impacts on the electric industry.

California law requires 20 percent of RPS by 2010. In my books, that's yesterday. It is aiming towards a goal of 33 percent by 2020. That represents renewable nameplate capacity totalling about 14,000 megawatts within the next few years, and 26,000 megawatts by 2020, of renewable natural resources.

At the same time, greenhouse gas from all sources, by law, must be reduced by 30 percent by 2020. In addition, a proposal is pending before water quality regulators, to ban once-through cooling technology in all generating plants.

These plants represent nearly one-half of in-state generating capacity.

The California ISO's strategic plan, is well aligned with these goals, and we are actively addressing these challenges in several ways: We have reduced the transmission financing burden on generating plants in remote areas, with a policy proposal made possible by your unanimous vote of approval.

We will facilitate the interconnection of new generation, which are mostly renewable, with a process that, with your approval, will significantly streamline the effort and allow the most viable projects to advance.

But as we experiment with these new rules, we expect a new challenge, so you may see more of us on this. I believe the last time my colleague, Mr. Perez, testified to you on that subject, at that time, which was only in March, so it was late in March, we had in the process, remaining, 60,000 megawatts or thereabouts, of interconnection requests.

Since then, and upon our filing with you, there was a rush to position themselves for -- actually, for developers to position themselves before the new rules come in, or in anticipation.

The addition in the last month in the renewable interconnections -- actually, all interconnections, which are majority renewables, is an additional 40,000 to the

60,000.

By the time I left the office about ten days ago, the amount of interconnections was close to 100,000, so as we solve our problems and as we file it with you, we'll experiment with you. Some of them will solve some of the problems, and some of them will not. I promise you will see more of me.

(Laughter.)

MR. MANSOUR: We recently completed conceptual transmission planning to identify possible transmission additions needed to meet 33 percent renewables for the portfolio standard, and presented it to the state policymakers.

The initial analysis shows that the 33 percent stage, will probably require six additional 500 KV projects. That is a total of $6 or $7 billion of investment in transmission, alone.

It is the beginning of an effort to understand the magnitude of the transmission additions that will be required in the next decade.

We're actively involved in the greenhouse gas regulatory design to facilitate alignment with competitive markets, and the future regional and national framework for compliance with greenhouse gas reduction requirements.

We are examining our markets and operations to ensure that we are providing incentives for investment in both services and facilities that will allow the existing fleet to function, deliver new infrastructure additions in time, and facilitate the integration of intermittent generation, while explaining the critical need to maintain the present capability of that generation fleet, which is essential for the integration of renewable generation.

That is something that has been missing in the understanding. Having a large renewable portfolio, needs support from traditional resources and some new ones, to make it all work.

These efforts include informing policymakers about the interaction among the state's environmental goals, with electric system operations, and the importance of coordinating their efforts to ensure their objectives can be achieved.

I am proud of the collective efforts of all the state agencies, to address these issues in an integrated manner, and understand the role of the California ISO in helping the state achieve its vision of the cleanest air and the cleanest water on the planet, without compromise to the reliability of the electric supply.

Future success for us and the entire industry, will require innovation in the operation, planning, market design, and regulatory framework, in order to keep the lights on at a just and reasonable price. What's worked in the past, will not be enough for the future, if even suitable. The gap is not indicative of a deficiency, but reflects the continuous movement of the goalposts.

You already know the desperate need for all the things that MRTU will provide and that Dr. Casey went through, but the question is, what else?

Instead of going through specific initiatives to fill the gaps, let me share what I believe the attributes of a properly functioning electricity market that we would like to see in California, should include. So, while we assess the progress on its own merits, we also assess where we are relative to the finish line.

Number one, we need greater benefits from resource adequacy. California's current resource adequacy program, looks forward only one year and does not incorporate the products required to take advantage of available technologies on the supply and demand side.

A multi-year framework will allow for meaningful cost/benefit cost comparison among alternatives, including new generating plants, retirement or re-powering of existing plants, new demand-response technologies, and transmission upgrades.

Second, lower ratepayer risks: A primary motive behind electric restructuring in the 1990s, was to shift investment risk from ratepayers to investors, yet today's practices rely disproportionately on ratepayer risk to underwrite new infrastructure investment.

For investors to assume these risks, however, market rules must be uniform in their implementation and application to all suppliers and all consumers.

Number three; consumer participation and benefits: Consumers should benefit from price transparency and competition among generation, demand response, and transmission alternatives. In California, demand response is provided largely by regulated programs designed to shed peak load under emergency conditions.

We have one of the highest percentages in the country in participation, just over five percent, however, demand should be able to compete with traditional generating resources to meet operational needs, and consumers should have options for providing demand response and receiving compensation whenever it is economically and practically feasible every day of the year, especially with the introduction of intermittent renewable resources of the magnitude we have.

Fourth, the market power mitigation: Market power has been characterized largely in the past, by a limited amount of suppliers, but when the buyer has that power, product standardization and price transparency, will be keys to achieving the benefit of competition.

Regional coordination: The most economic future resources, lie outside the boundaries of most states and service territories. It will be essential to achieve greater regional coordination in order to minimize consumer costs.

Six, regulatory innovation and flexibility: Changing resource mixes and demand participation, are rapidly changing the electric system operating environment.

Opportunities will be lost without greater innovation and flexibility, especially with regard to second-tier regulation affecting the electricity efficiency and reliability.

I'm sure this list can be extended, but if you were to ask me how close we are to those objectives, with all honesty, I would say, in spite of all the achievement that we have made, some of the solutions are in your own hands, while others are up to the state.

The purpose of today's meeting is the former, and in this regard, I offer the following summarizing comments:

We are proud of our achievement so far, and honest about what is left. Organized markets and ISOs, are better positioned than other models, to meet the challenge of the future.

Lastly, the gap between where we are today and our ideal goalpost position, will always exist, because the goalposts themselves will always move. From what we see, they are moving today faster than ever.

Thank you for your attention.

CHAIRMAN KELLIHER: Thank you very much. I want to thank both of you for your statements, and thank Dr. Wolak for joining you. I just want to say that the progress in California has been very impressive, particularly with generation additions and also improvements in operating performance and reliability benefits.

Just to follow on Dr. Casey's comments regarding MRTU, I mean, we will certainly watch the implementation of MRTU with great interest, and we will not merely be a spectator, so we will watch how it progresses after implementation, and we'll act, if necessary, and have the Commission connect quickly, when necessary.

But I just had a couple of questions regarding -- following off of Yakout's statement. On regional coordination, I'm just curious about that. What really is the best means to achieve greater regional coordination?

Im sorry, we should all have five minutes, I think, so I probably used up one of my five minutes, but what is the best way to achieve greater regional coordination?

MR. MANSOUR: Well, it's all about value.

California, especially the California market, is probably unique among all the markets, because it's surrounded entirely by non-organized markets, not in the negative sense, but just not structured markets.

We have pockets inside California, too, that were highly interconnected. When it comes to trades, for example, when you see day-to-day trades, and even the historical trades in the West, including California and the rest of the West, you can't say much negative about it.

It has been going great. The region has been utilizing all the diversity, both on the seasonal diversity and the portfolio diversity for many years, and it's been paying off.

When it comes to operations, I can assure you that when things are in an urgent mode, whether heat wave or whatever, all the operators and all the entities in the West, sit down and actually address the issues without any historical -- you know, from the organizational side, it doesn't carry any history.

So there are a lot of positive things that are there. The issue comes in the coordination, as we try to make structured rules in California, especially with the aggressive mandates that California has, and coordinate it with the rest of the West.

Now we're talking about coordination on the policy side, rather than the operation side, and that's where philosophy comes on strong. You're talking about in the Northwest, a system by which the majority of the system was built a long time ago, for a reason, and the reason has been largely benefitting a larger sector of public power.

It is natural for them to try to protect those benefits that have been there for many years. If we try to implement anything where there would be trades between what you have and what you have to give, you get the emotions.

Now, having said all of that, I think that with the introduction of renewable portfolio standards and environmental-related policies in most of the states, I believe that we have probably for the first time, the most compelling reason to have better coordination, because RPS on a regional level, is significantly more efficient than by state-by-state.

And interregional transmission is more important than it has ever been in the past.

So, it is just right now that I see the opportunity now and for the coming few years, there is more platform, more significant and stronger platform to bring this up. That's the value that we've been looking for, because, without it, you are not going to get a lot of coordination more than what has been.

CHAIRMAN KELLIHER: I have one narrow question, if I have any time, and that is, in your comment about lowering ratepayer risk, I don't know what practices you're referring to. You say that today's practices rely disproportionately on ratepayer risk to underwrite new infrastructure investment.

Are you talking about rate-based generation?

MR. MANSOUR: Yes.

CHAIRMAN KELLIHER: Or are you talking about the long-term contract? You don't view the long-term contract that a utility signs --

MR. MANSOUR: When you look at how it works now, you're talking about the Commission, the state Commission, obligates the regulated load-serving entities to acquire or make acquisition of a certain amount, based on their load growth.

So they go out and actually do bilateral or do an RFP, and they get proposals and they select whatever proposal. They present it to the Commission and the Commission granted them cost recovery on whatever they negotiated, and that goes to the ratepayers.

So, the acquisition is competitive, in the sense of who is the lowest bid in that process. But still, whether the decision or the context was wrong or right, or could it be any better, still it's all the ratepayers that are paying it, because it's a regulated rate of return that they have.

We do not see that there's a lot of appetite from the generator side, to build merchant -- truly merchant, where they take the full risk and build and then they go file their costs; it's all based, because of the financing issues and also the history of many of those companies, since the crisis.

So the system so far, even though the acquisition is competitive, but when you talk about at the end of the day, who carries that risk of decision, even through a competitive process, it is the ratepayers.

CHAIRMAN KELLIHER: I think my time is up. Colleagues? Commissioner Spitzer?

COMMISSIONER SPITZER: Thank you, Mr. Chairman. Yakout, you heard the discussion this morning of a few issues. Given the retail rate design in California and the long history of decoupling to promote -- intended to promote energy efficiency, and, I think, succeeded -- with retail rate design more in sync with competitive wholesale markets, what does that presage for distributed resources, demand resources, and issues such as the plug-in vehicle-to-grid, to resolve some of the distance between where you are and the goalposts that have been moving?

MR. MANSOUR: As I said, you know, the distance is still quite far, but the good news is, in everything we do on the wholesale level, we really coordinate very tightly with the State Commission and the state agencies, to make sure that what we do first, represents a building block on what we see coming in the future, and vice versa.

And I'm proud of that, and I'm sure the State Commission is also proud of that. That is one of the key things that happened since the crisis, that strong link between the ISO, the federal side of the regulation, and the state side of the regulation.

But still, there are certain things that I said. The vision that I shared with you, has what we see as the future for the market or attributes of a good market.

We're discussing this, and that is a vision that needs to be shared, not necessarily this exact one, but whatever it is, we all need to share it.

So when we then discuss the benefits or the merits, one proposals versus another, it is not just based on an isolated case and based on the documents supporting one or another; the benchmark is, how does that take us to that end?

Now, when we talk about, as I said, we would like, and we shared that with the State Commission, that we would like to move demand response from regulated programs for emergency, to everyday programs.

Now, when you do that, now we're talking about the whole thing is one link, all the way from the wholesale to the retail side. There is many things that have to change on both sides, on the retail, which is the state role, and ours.

Also with it, there's a lot of initiatives that are still historical in the state, that need to be resolved first. AB1X, which freezes almost the rates for half of the load, that needs to change in time, otherwise you have half of the system that's not really responsive to crises.

Implementation of technologies, there's a lot of stuff of that kind that we all understand, so it's understanding the vision first, and then working on the things that are standing in the way of making these initiatives work.

The actual contribution, major contribution that the state is proud of, the interesting statistic is that even though California has the highest rates in the country, the average bill is lower than the national average.

That means every dollar that was invested in conservation, demand response, and all of those things, pay back. So when you look at them in billions, it's a lot of money, but when you look at how it works and how it actually benefitted the consumers at large, in terms of what they actually pay, rather than the rate, it has paid significantly, and the state is committed to that track.

That's why you see all of those programs. You look at them and say, how much would they cost? I am not seeing strong pushback publicly to say enough is enough, because we are seeing first, the value, societally, and also they see that there is room to actually pay for better service.

COMMISSIONER SPITZER: Very briefly, for the Market Monitoring function, you don't seem to have the same level of public discord as in some of the eastern RTOs, but, nevertheless, given the rate structures and the relatively high rates, you doubtless get inquiries.

How do you articulate a distinction between what may be a high price, which is based largely on fuel prices, from a fair price, which is the market functioning properly, absent manipulation?

MR. CASEY: I think one of the key things that we track, as I touched on briefly in our slides, is a measure of how prices compare to a competitive benchmark. We do calculate our estimate of what we think the actual cost of serving power is, and that's reflected in the actual changes in fuel costs. So long as, on average, market prices are close to those competitive estimates, over a monthly or 12-month rolling average period, it gives us assurance that the market is workably competitive.

When you say a "fair" or "just" price, our focus, as economists, is, is the price reflective of competitive outcomes? That's what our metrics are geared toward measuring.

What we've seen over the past six years since the crisis, is that prices have been extremely competitive.

COMMISSIONER SPITZER: Thank you.

CHAIRMAN KELLIHER: Colleagues? Commissioner Kelly?

COMMISSIONER KELLY: Dr. Wolak, I know you have international experience in these wholesale markets. I wanted to take advantage of your experience, while you're with us today, and ask you, in particular, as you think about the three areas that you and Dr. Casey have identified for future market development for California, are there any models in other parts of the world, that you think will be particularly instructive to California or to us, in their efforts to accomplish these three goals, which are: Meeting the operational challenges that are imposed by renewable energy; development of real-price-responsive demand-response markets; and better coordination of long-term transmission and environmental planning? Is anybody out there doing it right?

MR. WOLAK: That's a very good question. I guess I would say there are certain countries that are far further along in terms of renewables. For example, in the Spanish market, they have on the order of about 12,000 megawatts of renewable facilities. In fact, in their control room, they have a system operator as well as a wind system operator.

It certainly changes the system operating paradigm. They are also blessed with significant amounts of hydro resources. I think that their experience is certainly instructive in terms of how to integrate more renewable resources.

In terms of the development of price-responsive demand, I think there, an interesting issue probably comes from the experience in the Nordic countries, where, effectively, they have the benefit of not needing interval meters to actually implement this, because it is a hydro-based system.

But what the effectively do, is, there is a very quick pass-through into the retail prices, of the wholesale price. True, it isn't profiled through, but in a hydro-based system, there's very little variation within the day, but there is certainly variation across seasons, as a result of seasonal differences in terms of water levels.

They find that they get a significant amount of demand shifting when there are low hydro conditions. I think the experience from there, would be very instructive for telling people, at least in the United States, the necessity of passing through the wholesale price signal.

The big problem at the state level, is, in the rush to protect consumers from price volatility, there's also the problem of preventing them from responding to price volatility to protect themselves.

Finding that balance, I think their market provides useful guidance on that, in the sense that they have a number of things in place where customers can go on the website to find out what their bill might be, from alternative providers, what various prices are, and there's quite a bit of information provided on that.

On the long-term transmission and environmental planning, I guess what I'd say there, is, most of the other countries in the world, haven't really had to deal with that, because they had the good fortune of having state-owned companies that over-invested in transmission tremendously, before restructuring took place.

In that sense, we in the United States are sort of out front on that one, because we don't have as much transmission investment.

COMMISSIONER KELLY: I like your take on that one.

(Laughter.)

COMMISSIONER KELLY: Yakout, I want to take this opportunity to thank you and the stakeholders at the California ISO for the amazingly quick response to the queue issue, and for developing the system so quickly, to better manage the queue.

I do understand your comments, though, today, that basically you figured you had a fix for it, then you got 40,000 more megawatts in your queue. I appreciate that.

MR. MANSOUR: Commissioner, I want to thank you and your staff, the Commission Staff, really, for working with us, trying to find solutions. We see how much you and your staff handle and how prompt are the responses. It's just amazing.

Every time we think we have a lot of on our plate, then we see what you do with those hundreds of decisions, and we think we're in a better position. Thank you.

COMMISSIONER KELLY: Thank you.

CHAIRMAN KELLIHER: Commissioner Wellinghoff?

COMMISSIONER WELLINGHOFF: Thank you, Mr. Chairman. Yakout, you're singing my song.

Demand response should be able to compete with traditional generating resources to meet operational needs, and consumers should have options for providing demand response and receiving compensation whenever it's economically and practically feasible.

MR. MANSOUR: Every day.

COMMISSIONER WELLINGHOFF: It's a wonderful statement and I want to say what I told you privately -- and I'll say it publicly -- I'll do anything I can to help you in that regard. I know we have some challenges in California, and I was very encouraged when, a month and a half ago, we had a demand response workshop here and we had a representative from the California Public Utilities Commission, and that individual told us that he's working on a staff white paper to go to the Commission to do, I believe, exactly what you're saying here.

So I'm very encouraged that we can all move together with the state and the ISO to get that done.

Let me ask you a little bit, though, about how demand response may fit in with your other challenge, and that is renewables. You've got 100 gigawatts in the queue. How much of that is wind?

MR. MANSOUR: When we had 60,000 megawatts, two-thirds of it was renewable, largely wind. Of the 40,000, the vast majority, is renewable and wind.

COMMISSIONER WELLINGHOFF: So, integrating that wind is going to be a challenge. I heard a number the other day. Tell me if it's close to being true, that there's a projection that there may be actually developed and put online, something like another 7,000 megawatts of wind in California in the next four to five years.

If that's true, you'll need another thousand megawatts of regulation service to take care of that.

MR. MANSOUR: I'll give you a quick brief on that. The 20 percent, which is in for 2010 and might have slipped to 2011 or 2012, a larger component of that, is Tehachapi development. The Tehachapi development will have over 5,000 megawatts.

You've approved the transmission and that is one place where you have about 5,000 megawatts of wind in one location that we're talking, over the next two or three years or so.

Our studies, which are not just studies, but we're implementing them, the impact of the 20 percent renewable, will require additional ramping capability of 30 percent, 30 percent more ramping that we've had in the past.

The reason is, the first three hours of a given day, the load ramps up by about 10,000 megawatts right now. If you combine that ramping up of load with the anticipated decay of renewable of about 1,500 to 2,000 megawatts in the same period, the other fleet will have to ramp up by the addition of the two.

Then, if you account for the possible error in the forecast of wind, that's about 500 to 1,000 megawatts of regulation that you would need to carry to account for that, which takes me to my point and back to your question.

If you back all wind with traditional existing resources, remember, as I said in my note, they are the same resources that would have emissions limitations on them, and some of them even would have venting and cooling, so development from the existing fleet, is likely to go down.

At the same time, investing in new facilities only for those services, would probably be not a very compelling business case.

Our hope is -- and, frankly, it's a very advanced demand response -- demand, if not fully, at least would partially carry that variation. Actually, at the ISO, we built a demonstration lab using existing technology, to show how, from end to end, you can actually connect those variations at the operator side, all the way down to actions at the retail side.

So, as I said, without that, the cost will be high.

COMMISSIONER WELLINGHOFF: To summarize, it may be essential to have more advanced demand response, including things like plug-in hybrid electric vehicles, just to make these renewables possible.

MR. MANSOUR: Correct. Of course, having a hybrid vehicle is one thing, and that is a great idea, and they're working on the prototypes and it might take a while to get the full scale of it, but there's a lot of other things you can actually adjust for demand, based on total comfort of the customers, without getting them too involved in monitoring prices and what have you.

You would have to have some things, as well as others.

COMMISSIONER WELLINGHOFF: Thank you very much.

CHAIRMAN KELLIHER: I want to thank the California panelists. We appreciate your help today.

We've heard from the East, we've heard from California, and next is the heartland, so the Midwest ISO and the Southwest Power Pool.

(Pause.)

Why don't we start with the Midwest ISO, and we'll start with Graham Edwards, Chief Executive Officer, and then turn to David Patton, who is still the President of Potomac Economics.

(Slides.)

MR. EDWARDS: Mr. Chairman and Commissioners, thank you very much for allowing us to speak today.

I need a six-year old to help me operate this.

(Laughter.)

MR. EDWARDS: Thank you very much for allowing me to be with you today, and for holding this conference.

As previous folks have said, there's been a lot of discussion over the last several years, relative to the values of RTOs and ISOs. What I hope to do over the next 20 minutes or so, is, from our perspective, help you understand what we see as the value that we bring to the Midwest ISO wholesale footprint, from a value perspective.

(Slide.)

MR. EDWARDS: If I may, just as a reminder, we are, first of all, an independent, nonprofit 501(c)(4) organization that is created in the public interest. We basically control the flow of power over parts of 15 states and the Province of Manitoba.

I have just a couple of key dates to point out for you: In 2001, the Midwest ISO became the first RTO to be approved by the FERC. In 2002, we began reliability coordination and tariff administration, in early 2002. In April 2005, we began the energy markets.

In September of this year, we will hopefully launch the ancillary services market. In addition, currently, we have approximately 300 different companies participating in our marketplace; 300 different market participants and that's about a 50-percent increase over what we had when we started the markets in 2005.

We have approximately 100 members and 26,000 individual balancing authorities at this point in time, that will functionally be consolidated with the implementation of ancillary service markets.

We clear about $3 billion a month in our market, and in the 15 states that we operate in, it's a challenge, because part of them are traditionally regulated states, and part of them have been restructured, so trying to balance that and coming to a common consensus on various things, whether it be demand response or whatever, is a real challenge for us as we go forward.

We've been in the business ten years, and we're going into our fourth summer of operations. We're very different from PJM, who's been in business 80 years. We're still a very young organization and have come a long way, and I would say we still have a long way to go.

(Slide.)

Just to remind you of what we do. First of all, we think we provide solutions to challenges and opportunities within our industry. That goes back even to Order 888, to wholesale competition, to where we provide independent transmission system access on a non-discriminatory basis. Before the Midwest ISO versus after the Midwest ISO and non-discriminatory access, it really did level the playing field for the smaller players that needed access to the transmission system to make transactions.

We deliver improved reliability coordination. We have visibility over all 26 balancing authorities into our neighbors -- SPP, PJM, TVA: a lot of different markets as well as non-market organizations -- that we have access to as far as data goes. I'd like to say we see broader, deeper and faster than we ever have before, which definitely improves reliability.

We also perform efficient wholesale market operations, lower unit commitment costs, better dispatch and better congestion management. Prior to the current five-unit redispatch, where we managed congestion on the transmission system -- that was the old TLR system -- Dr. Patton has estimated that the first year after the operation of the markets and the five-unit redispatch, we have sold approximately 500,000 TLRs after the market started. We assume the TLRs are probably going to occur a lot of the times during the peak periods with higher prices, and consume $100 a megawatt hour. It's about $80 million worth of value annually we would provide through the unit redispatch.

We've also seen improvement in capacity factors over the last several years. From 2000 to 2006, baseload capacity factors throughout our footprint have increased approximately 25 percent. Intermediate capacity factors have increased about 46 percent. Our current peaking capacity is being utilized about 4 percent of the time.

In addition to those benefits, and what we do, the coordinated regional planning I've heard you talk about on several occasions in questions that you have -- to me, the regional perspective is more appropriate. You get a better plan, which means you get better economic investment in the transmission system, which equals better reliability.

I've said in the past that today's economic project is tomorrow's reliability project. We need to look at both, and we do.

Last but not least, we see ourselves as developing a platform for wholesale market development, which includes development for demand response initiatives and development of wholesale platforms, so people can participate on the demand side and so demand can participate, such as a generator, in addition to how do we integrate renewables -- and we've heard a lot about renewables today, which I will talk about further in just a moment.

(Slide.)

That's what we do. Let me talk just a moment, if you don't mind, about how well we do it, and the value that we bring to the Midwest ISO wholesale marketplace. I want to spend a little bit of time on this slide, if you don't mind, because this is the crux of my comments.

Basically, when we started the energy market, our stakeholders started, day one, asking the question: help us understand the benefits that you're bringing, and improve the benefits to us. We tried to do that in one simple study, from a production costing study. But there was more value there than just one component.

What we did is, we initiated last year a total value proposition analysis throughout the Midwest ISO and the different components that make up that value. Let me walk through this, if you don't mind, and try to explain to you why the footprint is better off today than it was ten years ago, before the Midwest ISO.

Let me focus your attention on the right-hand side. The furthest vertical right-hand bar, net benefits, $555,850,000. We feel that is the value we bring to the footprint on an annual basis. Let me start at the left-hand side and walk you across, what that really means, and how we've gotten to that number.

Improved reliability -- you've heard a lot today about improved reliability, because of organized markets, because of RTOs, ISOs. If you take a look at the tools that we have, we have over 240,000 individual data points come into our control room every four seconds. We have a state estimator that provides about 8500 different contingency analyses every three to five minutes. We have a lot of data.

As I said, we see broader, we see deeper, and we see faster to improve reliability. If you take a look at the probability of an outage, before the Midwest ISO tool was in place and afterwards, the probability has been declining about 64 percent because of what we see and how we can look at disturbances on the system, and how we react before the occurrences actually happen.

In addition to that, outage size has been reduced by 32 percent. We can confine it to smaller areas based on what we see with the data and tools that we have. In addition, the outage duration has decreased about 18 percent because of these same tools.

So as economists apply the differences in these outages -- probability, duration and size -- that's where we develop the numbers of savings and value of $230- to $340 million. I don't think anybody in our footprint would question that reliability has increased significantly with the Midwest ISO and with the Midwest ISO markets.

The next three bars are what I would refer to as market deficiencies. The first one is a dispatch of energy production costs that would be dispatched over a broader area, more economical generation being shared. That redispatch and those economics -- between $200- and $250 million -- also includes the next PLRs.

The next bar is the disposition reserves, the deployment of reserves, both regulation and operating reserves. This is what we will see as we implement the ancillary service markets in September of this year, between $115- and $205 million.

The next bar is contingency reserves. Beginning in January of 2007, we deployed the contingency reserves throughout the footprint, and we began collecting data in 2006 on the amount of contingency reserves that were being held by our markets by the members during 2006, before we implemented contingency reserve sharing, then in 2007 after we implemented. The difference in those reserves is how we calculate the value of $140 million.

We had a stakeholder group help us develop and buy in, if you will, to the methodology of how we calculated that value. Those are hard numbers. In fact, if you noticed the footnote, if you looked at the 12 months ending May of this year, the 12-month rolling average, it's been about $137 million of documentable demonstrated benefits that we've seen.

The next bar is generation investment deferral. For every one megawatt that we defer because of increased sharing and planning reserves, between our participants and our members, for every one megawatt that we can reduce in our planning reserves, that's about $1.2 million of avoided construction costs.

When you take a look at a footprint the size of ours, a 116,000-megawatt peak, around 130,000 megawatts worth of generation, that would equate to about $135- or $150 million investment deferral in value of benefit to the footprint and the members in our footprint.

Summing all those up, between $800 million and $1.1 billion -- and our cost to deliver that value is about $250 million annually; that includes administrative costs, depreciation, amortization -- our all-in costs to run the

Midwest ISO is what that is, thus getting us back to that quantifiable value that I said to start with, between $555 million and $850 million.

In addition to the quantifiable issues, there's a lot of values that are qualitative in nature. Price transparency -- one of our vice presidents was testifying before the Senate Energy Committee in one of our states, and was asked by a senator, why was the price in Minnesota X and the price in Iowa Y? Why was there the large disparity? He said, instead of answering that question with specifics, he said that before the Midwest ISO market, you would never have known what the prices were. So price transparency is important, understanding what those LMPs are.

The last two blocks here, wholesale platform for demand response -- we have the capability, and are creating, that platform to better enable demand response at the wholesale level, not the retail level, but at the wholesale level.

In addition, the platform for renewable portfolio integration -- these are the challenges we see as we move forward. We've made improvements, but we can continue to improve, and you've got our commitment that we will do our best to continue those efficiencies and improvements, both market design improvements as well as operating improvements.

(Slide.)

Going forward, we have always said we were a solution to some issues. We still have issues and challenges and opportunities going forward. Renewables, primarily wind integration, I want to talk about in just a little bit. But some states are addressing the policy question right now, what renewables should be.

We think it's incumbent on us to help facilitate and help find solutions on how the most economical way to do that is. We need to help those policymakers understand what the costs are of the decisions they make.

Demand response and smart grid integration is the same. We need to help facilitate that. There are some major changes we think we can help facilitate to help demand response.

As far as infrastructure development and cost sharing, transmission construction as you have heard is critical. But I will say cost sharing -- I'll say it to you once and I'll probably say it to you again -- is probably the most contentious issue that we've got to deal with within our organization and with our stakeholders going forward.

(Slide.)

As we look at renewable integration, as this map shows, the position of potential wind resources that could be located throughout the country -- this was a 20 percent by 2030 wind integration study done by DOE -- the dotted ovals there you see are where the primary locations would be. If you take a look, a lot of it is located within the Midwest ISO footprint, which is a lot of challenges for us. You've got to look at what are the planning uncertainties related to the carbon and carbon future. How does that impact renewables, the amount of renewables?

Also, across 10 of our 15 states, they have either mandates or goals in place. With the renewables and with potentially this amount of renewables and wind located in our area, there's a major transmission investment question out there. We've got to make decisions, and we can't wait till the end of the day to say where exactly is this going to be located. We need to be making decisions as we go forward.

As we look at it, one of the issues that we continue to try to deal with --

(Slide.)

-- as Mr. Mansour was mentioning, is the queue requests. We continue to see a substantial increase in the number of requests in our queue. If you look over on the right-hand bar, currently we have about 85,000 megawatts of new generation requests in our queue. 69,000 megawatts is wind.

In looking at it over our states at this point in time, we have about 13,000 megawatts of mandates throughout our footprint. That does not include goals, but mandates. So basically what I said is, we've got 69,000 megawatts of supply chasing 13,000 megawatts of demand. It's all not going to be built.

Probably a lot of this is in other peoples' queues -- California, ERCOT, or whomever. We filed last week with the Commission on our proposed recommendations on initial steps to fix the queue, and we're looking forward to that response.

Just as a matter of information, currently what we're experiencing is that only about 30 percent of the requests go to fruition. About 70 percent of the requests drop out before the end of the time frame.

(Slide.)

Demand response and smart grid initiative. I've always said that I'd rather save a megawatt than build a megawatt, because I'm saving the reserves on that megawatt. It's more efficient, more economical.

As we look at demand management, demand response and energy efficiency, it's going to take both of them to go forward. Within our footprint, within our 15 states, many of the demand response programs we have are legacy-type programs, traditional interruptible load programs to major industrial customers. Right now we have about 8600 megawatts of interruptible load on our system. Most of that is for reliability reasons. There is some price-responsive interruptible load included in there.

We have a mixture of retail choice and traditional regulated states, which I mentioned really is an issue that we have to manage very, very carefully. The retail regulatory treatment does not always align with our wholesale marketplace. Incentives for load-serving entities need to be reviewed, because to me that is where you're going to look at getting the retail side of demand response implemented.

What we've got to do is continue to work in the regulatory arena, financial, and address our technological issues in order to better enable demand response at the wholesale level. It also needs to be worked in conjunction with the retail level.

Currently we have two groups working, one within the Midwest ISO that Chairman Norris of Iowa is chairing and heading up a demand response group, and also the MWDRI, the midwest group. Within those groups we are trying to identify and work collectively with everyone to how do we better integrate demand response into our platform to make it more feasible.

The bottom line is, we need your help, and we need all the RTOs and ISOs working together to provide a better platform and better solutions to demand response initiatives.

Lastly, what needs to be constructed from the infrastructure standpoint? We don't need to build just generation or just transmission or just demand response. We need to consider everything. We need a balanced portfolio of all those items to meet the future of the country's energy requirements going forward.

Who pays is the real question. We hear beneficiaries should pay, so how do we share these costs? How do we share them over 15 states? How do you share the cost of the vast amount of transmission investment that's going to be required with renewable integration?

Those are the questions. And I said before, the cost sharing issue is the most contentious issue that we're dealing with right now within the Midwest ISO. Also, how to complete this. Siting, cost increases in materials, steel, labor -- all those items -- impacts on how do we complete it. Not in my backyard is an issue, and also timing is an issue also. We need policymakers to make decisions so we can get infrastructure built, and steel in the ground, going forward.

Just finally, and I appreciate your patience with me, the benefits we think that we have demonstrated, from improved access, improved reliability, efficiencies in planning, and we think we have done it in a cost-effective manner. And we think that the Midwest ISO is in the best position to help address some future challenges, as well as the other RTOs and ISOs. We look forward to doing that and helping the industry where we can, and being a resource for this Commission.

Mr. Chairman and Commissioners, thank you all very much for providing me the time to provide these comments.

CHAIRMAN KELLIHER: Thank you, Graham. David?

MR. PATTON: Good afternoon. Thank you again for allowing me to come and address the Commission on the state of the market.

The Midwest ISO is the second-most-complete set of markets --

(Laughter.)

MR. PATTON: I'm kidding.

(Laughter.)

MR. EDWARDS: And we might be looking for a new monitor.

(Laughter.)

MR. PATTON: Potomac Economics serves as the independent market monitor for the Midwest ISO. They're somewhat different than the bifurcated structure that exists in the northeast. We perform the entire market monitoring function as an external entity, so our role is somewhat different in the Midwest ISO.

This presentation, again, is going to review some of the findings we saw from the 2007 state of the market report.

(Slide.)

The Midwest ISO started its current centralized markets on April 1, 2005.

(Slide.)

What they're currently operating is day-ahead and real time energy markets and a market for financial transmission rights. It's a relatively limited set of markets compared to the more full array of markets that exist in some of the other regions. They're soon to be augmented by ancillary service markets, both regulation and operating reserve markets, in the fall of 2008. That will be cooptimized with energy and achieve most of the same benefits that I talked about previously that you can achieve from cooptimizing ancillary service and energy markets.

One of the conclusions you'll see at the end of this presentation is that while the capacity margin has been falling slowly in the midwest, the signals really haven't been there to build new generation, and that's the case for two reasons. One is, there isn't a good mechanism right now for shortage placing. We saw shortages in the summer of 2006 and 2007 that resulted in emergency actions taken by the Midwest ISO. Yet in many of those hours, the prices were in the $100 to $150 range, not reflecting the fact that we were taking extraordinary action in either curtailing load or running short of operating reserves to satisfy the energy demand.

That will in part be remedied by the implementation of the cooptimized reserve markets, which will attach an economic value to operating reserves. And when they run short, that will be reflected in prices. That's an important component of the overall incentives for people to build in these markets, as you recognized in your Notice of Proposed Rulemaking on coordinated markets.

MR. PATTON: The second issue relates to capacity. I don't we can talk about this, because it's pending. But Module E has been significantly improved to govern resource adequacy. That should help as well.

(Slide.)

MR. PATTON: I'm not going -- I think Graham did a great job talking about the benefits of the Midwest access, so I'm going to skip this and replace it with some of the unique challenges the Midwest ISO faces.

One remarkable thing is the sheer scope of this market, and the fact that this is really the first market put in place in an area where you have decentralized operations prior to the ISO. In most of the other areas, particularly in the Northeast, you have power pools operating. So there was already a degree of coordination and software, importantly, in place, where you could layer a nodal market on top of this.

This is like the creation of a nodal market from scratch in an area where frankly I was holding my breath when it all started, because the challenge was enormous. I think the markets have performed fairly well. The operations initially were somewhat conservative. That led to higher levels of uplift.

But think we've seen in our state of the market reports analogies we've done that operations have improved over time. Upload costs have fallen, and things have improved quite a bit.

One of the other important or two of the other important challenges that you can't lose sight of in the Midwest ISO is they're subject to a tremendous amount of looped flow, the flow across the transmission system, affected by what people are doing in Canada, PJM, people all around them.

It makes the operational challenges much more difficult. You have to anticipate that when you sell transmission lights, so you don't held them when you commit demolition, so your transmission system doesn't get overloaded. It's a continuing challenge for the Midwest ISO.

Secondly, is the number of interfaces in all directions really. That results in highly valuable imports and exports, really on a 15 minute basis, that causes the price volatility in the Midwest ISO region to be almost twice what it is in the Northeast.

Again, it presents operational challenges when people change their imports and exports drastically. You have to make sure you have enough generation or demand response or something to be able to respond.

So there are quite a few operational challenges, and I think the ISO has consistently improved over time in its ability to handle those.

(Slide.)

MR. PATTON: As far as the broad conclusions of 2007, we performed the same sorts of competitive screens of market participant conduct and founded the energy markets competitively in 2007, notwithstanding the fact that there is a fairly high degree of local market power in many areas in the Midwest ISO footprint.

In roughly 60 percent of the constraints that bind, you have to have resources of one participant to resolve the constraint. We call that sort of participant a pivotal supplier. That's market power mitigation.

In many cases, they would have the opportunity to significantly raise prices or raise uplift when we have to pay them to commit generation to resolve the constraints. What we found was that the conduct has been relatively competitive in the area, resulting in competitive outcomes, and in part I think that's due to the market power mitigation measures that are in place to deal with those issues.

As far as the results of the energy market, the price has increased by 13 percent in 2007, which is basically in line with the increase in fuel prices in addition to the gas and oil price increases we saw in 2007 you'll see in next year's report. I'll give you a forecast.

Coal prices have really taken off. In a large portion of the off-peak hours, coal is on the margin, both with PJM and the Midwest ISO. So it's affecting prices significantly in ways we haven't seen in the past.

Upload costs and congestion costs also increased in 2007, due in part to fuel prices but also due to lower imports from Manitoba, which caused increased congestion on the system.

(Slide.)

MR. PATTON: This shows the all-in price by market in the Midwest ISO region. You can see the natural gas prices superimposed on this chart, and in addition to the fuel price changes, there are notable increases of prices in some markets in February 2007, due to extreme conditions.

Both price movements are actually understated, because of the issues related to shortage pricing that I discussed earlier.

(Slide.)

MR. PATTON: So in conclusion, although we identify a number of issues in the state of the market report, many of these issues are addressed by the implementation of the ASM markets. The report also includes eight additional recommendations that I've categorized in three areas.

One is improving the price of energy when demand resources are called and facilitating programs. That will help facilitate more demand response in the region. I actually don't necessarily agree that you have to pass through prices at the retail level.

I think the New York programs are a good example of how an RTO can facilitate demand response without prices being visible to the retail customer. But I'll wait until the question and answer period to talk about that. If you have questions, I think there are a number of ways that the Midwest ISO can improve how it schedules imports and exports, to better manage the imports and exports and reduce the price volatility in the market.

The rest of the recommendations really relate to operational issues that are probably not worth going into now.

But I think there are a number of areas where there are potential improvements, where potential improvements can be made, and I think with the final conclusion regarding the price signals, I do think with the implementation of ASM and the Module E changes, we'll be close to having a design that will support new demand, I'm sorry, new investment in resources, whether it's demand or supply.

The one missing link is allowing demand response to set prices, because the Midwest ISO has something like 45 percent of their curtailable load in all the areas. The primary actions that are taken will be given to an energy emergency.

If it can't set prices, the true value of energy in those periods is not visible, and that signal is not being sent to potential developers in demand response. Thank you.

CHAIRMAN KELLIHER: Thank you very much. We now turn to Nick Brown, the President and Chief Executive Officer of Southwest Power Pool.

MR. BROWN: We're actually going to work together through the presentation. We thought it might flow a little bit better. I'm kind of tempted to just say ditto from all the previous presentations.

I'm almost singing the sixth verse of the same song. It has been a very positive experience within our footprint, but I think we can put a few little different spins on our experience within these markets, so we'll give it a shot.

(Slide.)

MR. BROWN: The first point I want to make is that within the Southwest Power Pool footprint the primary driver for all of our markets has been to uphold reliable operations.

Do you really believe that our primary job is being really the reliability coordinator in the footprint, and they are an enabler to us in doing that more effectively than we could without those markets?

With that being the very foundation, I think one of the markets that we implemented first back in 1998 within the Southwest Power Pool footprint was for regional transmission service.

I think somehow in the discussion of the value of regional transmission organizations, we forget that we collapsed within the SPP footprint 14 different steps of rates, terms and conditions that were under your jurisdiction, to one set of rates, terms and conditions.

We provided one-stop shopping for transmission service across our entire footprint, in terms of what that's done to adjust the bilateral wholesale market within our footprint.

It's pretty impressive, and Richard's got a slide to emphasize that point.

MR. DILLON: Since 1998, the transmission revenues within SPP have grown significantly. That has been due to the collapse of all of those separate tariffs into a single bundled retail load moving over to network service.

In fact, the energy market design also

capitalized upon that. These load areas now have the ability to move energy from any resource within SPP to the load, without any incremental cost. So they have benefitted from a much clearer, much easier transmission of energy from any of those resources, including that under the energy market.

MR. BROWN: A key point here is that in going into the collapsing of those individual tariffs into a single regional rate, the concern was that all we're going to do is reallocate the existing revenues.

The reality was the pie got bigger trough the effectiveness and the efficiency that was afforded through a single set of rates, terms and conditions across the footprint.

Then last year, last but certainly not least, among our RTO/ISO organizations, STP implemented our energy and balanced market. As we were recognized by this Commission as an RTO, our state placed upon many of their jurisdictional entities the obligation to show, come before them and show that there was benefit to their continued participation in the Southwest Power Pool organization, despite the fact that many of these companies had been members for 60 years.

Fortunately, those states that did not require the showing, agreed that a single study could be performed on behalf of many of these organizations across all these states. That study was performed under the oversight of our regional state committee by observing the development of the procedure where this particular study was concerned.

But the approach taken was quite conservative in terms of showing the true benefit of the Southwest Power Pool region. But at the end of the day, when the results were published, they had shown a forecast of over 270 percent return on investment for participation on the Southwest Power Pool market, specifically the energy imbalance market and Richard's got more specific data on that.

(Slide.)

MR. DILLON: From the cost-benefit study that's performed not as a requirement during a spot market, but in order to demonstrate to everyone the value, the study demonstrated that there were 1.2 billion in production cost savings to the eastern interconnect, because anything that one RTO does affects everyone.

In addition to that, there were $614 million worth of trade benefits or cost savings just to those entities within SPP. The cost, in order to do that, was substantially less, resulting in a net benefit that persuaded all the parties that this would be a good move to make, and for the year of 2007, I will reference back in just a second.

There was a production cost estimate of $86 million that would be saved on the basis of all board. The boards, the RSC and everyone else said let's go ahead and bring the spot market up.

MR. BROWN: So a key point here is just in the study that Southwest Power Pool had done, that showed benefit to those outside of our region. Likewise, we know we benefit from the existence of the organized markets that we are neighbors to.

Well, not only did our states require that we forecast and show on the front end the benefit of moving down this road; they also required that we track the actual experience as we went into these markets. I mentioned earlier we're in a year into that actual operation. We did perform that analysis.

I'm happy to report that despite the conservative approach taken in the forecast, and the fact that the forecast projected significant savings, the actual experience, even though I believe these calculations are also very conservative, exceeded the forecast. Again, Richard has more detailed information.

(Slide.)

MR. DILLON: The market that SPP brought up had some differences from other markets. One is it is a spot balancing market. It is a spot market. Another difference is that the form of transmission rights that was implemented actually supports network transmission, which allowed parties to more easily hedge the load to the cost.

Another item that there was lots of debate about right at the beginning was that there's going to be a voluntary market. What that meant was that the resources were not required to offer. They could self-dispatch.

In this voluntary market, 80 percent of the energy during the 12 months that we were evaluating was provided by resources that had offered. I'm not talking capacity. I'm talking actual 80 percent of the energy consumed was through offered resources.

Market participants saw value. We went back and calculated, based upon actual experience, what was the estimated savings. Now these savings are based upon only eight percent of the financial settlement is using spot prices, which represented about one and a half billion dollars' worth of transactions.

The other 92 percent had been either self-arranged or bilaterals.

(Slide.)

MR. BROWN: Out of that eight percent, there was an estimated benefit, trade benefit or production cost savings of $103 million. That $103 million was for 12 months. It sounds high, but actually it is real, although it sounds made up. But our budget was slightly under $100 million for that same 12-month period.

In the analysis, we did a lot of sanity checking and kept coming up with approximately the same number. This benefit was very conservatively calculated. We took no credit whatsoever for the intermittent or wind resources, under the presumption that wind was going to happen whether we had a market or not. So savings for wind resources were excluded.

Anything else that we had going on that was not directly market-related was excluded with respect to the spot benefit. This did not include the fact that there was a much fuller utilization of the transmission grid.

During the utilization of the transmission grid, there was a lot of concern about well, the spot market may take away from the bilateral transactions. We also examined point to point non-firm transactions and saw that they did not drop.

As they were going through this, those bilateral transactions, at least at a level we still maintained, because that is important because it's also a transmission revenue, the other market, if we went through, we also filed a state of the market report.

(Slide.)

MR. DILLON: And I have performed a similar test. This is one of those little items that the spot prices themselves are not sufficient to justify on average the sighting of any particular generation. That's not what's going to pay the bills. I said by itself and I said on average, because there are averages which definitely have pricing that could indicate that siting of generation or improvement of transmission would be needed.

MR. BROWN: So bottom line, even with very conservative analyses, the benefits have been tremendous. So the next question asked of us is what's happening with electricity prices, and again, sixth verse of the same song. They're increasing.

But also, similarly to what you heard earlier, the reason for that, consistent with the others, at least in the Southwest Power Pool footprint, is the increase in cost of natural gas since the beginning of this year in our region.

It increased from roughly $7 to over $12, and also maintenance outages of both nuclear and coal units again, placing gas in the margin more frequently, and Richard has some additional data.

(Slide.)

MR. DILLON: Again, as far as the state of the market, the state of the market report looked at how much of the actual production was produced by what type of fuel source.

For purposes of slide, we've broken it down into three major groups. The intermittent resources, which includes wind and run of river and tidal resources, coal and nuclear and gas. Gas production accounted for roughly 26 percent of the energy consumed during the period of February '07 through December '07.

Twenty-six percent of the energy was produced by gas. However, over 80 percent of the time the gas was marginal. That's not surprising to anyone. That did help drive the prices up. You notice that it's 100 percent of the time.

So even though our prices have gone up, they're not in lock step with the gas prices at this time. The SPP footprint, we will see 25 to 50 percent swings from peak load to 3:00 a.m. in the morning, which means that the coal and nuclear comes back on margin for a lot of hours, during the wee hours of the morning, and helps dampen the impact of rising gas prices.

MR. BROWN: So the next question is what is being built and what needs to be built? The answer in our footprint is primarily transmission. Many years back, again coming out of our RTO recognition, where our regional state committee was given the responsibility for determining how to allocate costs for transmission expansion, they went to work very, very quickly.

I enjoyed meeting with several of you yesterday, and getting more detailed accounts of that history. Bottom line, I was very pleased that commissioners from six or our states were able to get together, propose to us developed tariff language to be filed before you, for allocating costs for transmission needed for the liability upgrades.

That has proven very beneficial for us. We do have congested areas in the SPP footprint. Richard had a good depiction showing that, and also good information about the amount of transmission that has been built for reliability needs.

(Slide.)

MR. DILLON: The chart that's before you is actually for the 13 months ending April 2008. It includes April of '07 through April of '08. The reason is we started the market in February and let things settle out.

You will see on the chart, especially on the left-hand side, our most constrained area is the Panhandle of Texas down into New Mexico. We have another minor constraint that does not show up very well on this particular chart. It's in Northwest Arkansas that we have been dealing with.

The Northwest Arkansas area has been doing transmission upgrades, and also has been doing generation siting in order to alleviate their issues.

The Panhandle of Texas requires a lot more extensive work, and if you look down that entire left side of the chart, Panhandle of Texas all the way up through Texas, that also happens to be where the wind siting needs to be.

So we are struggling with the congestion that is within that area, and that's the primary side for wind, and utilization of that wind throughout our footprint is also near that congested area.

(Slide.)

MR. DILLON: In regard to the cost of the transmission, the reliability projects that were in our most recent transmission expansion plan were about $762 million. The board has gone through and issued notices to construct about $700 million now.

The part to pick up on this pie chart, there are two very major items to notice. Out of that $762 million, only 42 percent is actually new lines. The rest is actually dealing with trying to update the infrastructure, because we have aging infrastructure out there.

For reliability purposes, which is keeping the lights on, we have quite a bit of upgrade that needs to happen.

(Slide.)

MR. DILLON: In regard to the reliability and the economic project and some local zone projects, we're looking at an investment of $2.2 billion. That $2.2 billion, again looking at the breakdown, 55 percent of that is related to new lines.

The rest of it again is dealing with the infrastructure that we have in place currently, and the economic projects. The projects will be anything that is not reliability. It's kind of like it's in one bucket or the other. This is something that SPP has definitely been keeping an eye on.

MR. BROWN: I've shared with you on any number of occasions my thought that we have in our industry ten percent of our asset base constraining 90 percent of opportunity. Quite frankly, it's just because we're not building transmission to enable markets the way I would like to see us focus.

With that in mind, we have talked for many years about the need for regional planning, and putting large regional and interregional plans together. My observation again has always been it's really not a matter of putting plans together.

We've been doing that for a lot of years. They look really good. They're well-published. Then we put them on the shelf and they sit there. The need is to build, and the only way we're going to build is to determine how to allocate costs.

As I mentioned earlier, we had gotten a wonderful shot in the arm with respect to needed reliability upgrades on a regional basis, based on the work of the regional state committee.

We've analyzed strategic planning process in 2006, asked our regional state committee to take on the economic upgrades, those needed to really take us to where we needed to be to make our markets work the way they can.

We're excited. Again, we visited with many of you yesterday, with your staffs. By the end of this month, it is our great expectation that the regional state committee and our board will approve tariff language to allocate costs for economic expansion within our footprint for a balanced portfolio of transmission upgrades, on a postage stamp rate across our entire region.

We hope to immediately, following board approval, file that before this Commission, and the creative thinking that occurred in this process, to come up with a balanced portfolio of transmission upgrades to satisfy the diverse interests and needs of all our eight states was just tremendous.

It is the result of over 75 meetings, most of which took place face to face really by teleconference, but the commitment was great. I want to take this opportunity to kind of take my hat off to the members of our regional state committee, particularly their staffs, the staff of Southwest Power Pool, who supported the efforts of those groups through analysis upon analysis upon analysis.

At the end of the day, it was not data and the education that took place in those meetings and forums, that led us to the conclusion that it is appropriate to share on a postage stamp rate that which is needed to build out the interstate Highway system, whether in the Southwest Power Pool footprint.

So more to come on that. Just again, I wanted to take the opportunity here to thank all of the folks who have put in a tremendous amount of effort.

You heard wind before; you'll hear wind again within Southwest Power Pool, I'll tell you about how much wind is in our footprint. Richard, if you'll just put up that next slide?

(Slide.)

MR. BROWN: We're currently at 2,000 megawatts for a roughly 45,000 megawatt region, that I say today because every day continues to go up. Clearly, we're all struggling with how to manage our generation interconnection queues.

We're no different in that regard. But again, it begs for an interstate Highway system to really facilitate the placement of those wind resources. Like the other regions we know, that all of that particular capacity won't come to fruition.

But at the same time, we very often see reports and announcements that are more sure of what's in the queue that aren't even in our queue yet. The uncertainty is great; the numbers are great; the technical challenges are great; the political challenges are great.

But with all that uncertainty, it simply reinforces the need to build out an interstate Highway system, to produce more options to create more availability to many diverse loads seeking that type of renewable power.

(Slide.)

MR. BROWN: You'll see on the slide now before you, what we have envisioned as an extra high voltage overlay. In fact, a good portion of the lines that you see are expected to operate at 765,000 volts.

Currently within the SPP footprint, our maximum voltage level is 345. So this is a whole new world for us.

MR. DILLON: I just want to point out that our thinking now has exceeded beyond ten years. We can no longer just sit to look and plan with a ten-year horizon.

MR. BROWN: In fact, this particular study was looking at 25 years into the future, and what is really needed from our transportation system in order to accommodate not only the SPP needs but our national needs.

So now let me shift to the challenges. Again, I feel like I'm singing the sixth verse of the same song.

(Slide.)

MR. BROWN: Again, I feel like I'm singing the sixth verse of the same song.

(Slide.)

MR. BROWN: We have growing demand in our footprint. In fact, in our 411 data, we have shown over the next ten years, I think, a fairly conservative forecast of increased demand growing at 1.5 percent.

We'll need another 10,000 megawatts of generation. Clearly, all of that cannot come from renewable resources, in order for us to maintain reliable operations in our footprint.

Also, in our footprint, there's a large opposition to coal for greenhouse gas emission reasons. I'm particularly troubled by that, because quite frankly, I think we need all options on the table. Not one of two; we need all options on the table.

We've seen the price of natural gas in our regions. We've seen the variability of renewable resources. We will need baseload capacity in order to balance out the technical challenges with the renewable resources, transmission expansion for economic reasons.

The biggest challenge, and again I completely agree with Graham on this, the biggest challenge is cost allocation for the transmission needed, for economic reasons. While I can celebrate, at least within our region for a balanced portfolio of expansion opportunities, we really need to tackle this particular issue an on interregional basis.

I would really look at this Commission to help us work through those challenges. They are great, but we really needed to take the bull by the horns on that particular issue. So are we responding to the challenges?

Again, the cost allocation for economic upgrades and transmission expansion is one of those ways that we are an infant in the development of our markets. Our energy in day ahead market has only been place one year.

We helped to complete a cost-benefit analysis in October on the day ahead market, with centralized unit commitment and ancillary service markets for balancing regulation and for operating reserves.

Clearly, with the magnitude of renewable resources contemplated in our footprint, the regulation market is going to be so important that all of these markets move forward with the assumption of a consolidated balancing authority within the SPP region.

I know this Commission has asked us on any number of occasions to continue to assess moving in that direction. Clearly, in implementing these ancillary service markets, that will be a foundation that will have to be in place.

I'll end my comment with a plea for more research development and demonstration dollars. I currently am serving as the ISO-RTO Council representative to the Electric Power Institute Board of Directors.

EPRI has taken on the goal of some fairly large demonstration projects, to deal with the global warming issues. These will require additional dollars. Smart Grid we've heard discussed a number of times today. EPRI has a wonderful initiative focused on Smart Grid.

But I do want to add a particular definition that I don't often hear. Within the EPRI materials, and in particular Steve Speckler will discuss Smart Grid in terms of defining it as prices for devices. I think we talked a lot today and I heard others discuss about sending price signals to customers.

I would offer the EPRI definition. What we really need is the prices to go all the way to the end use load for the device itself, the reason being I for one don't see customers sitting at home and monitoring electricity prices in real time.

The devices are smart enough to do that for us, the instructions that the customers would give these devices. But here's the point. That big infrastructure, we don't have that infrastructure in place today, and to do it right, we really need to be investing in demonstration projects from which we can learn the best way, before we spend tremendous amounts of dollars implementing that type of infrastructure.

If we implement wrong on the front end, we'll waste time and we'll waste energy. My shameless plea then is to refocus everyone on the very large benefit of spending dollars and investing dollars in research development and demonstration projects. Thank you.

CHAIRMAN KELLIHER: Thank you very much. I want to ask the panelists or anyone are you planning to stay until 3:30? Are you all comfortable with 3:30? Why don't we go with eight minute rounds. Let's start with Commissioner Wellinghoff.

COMMISSIONER WELLLINGHOFF: Thank you, Joe. I appreciate it. I'll be quick, because I've got to leave in about five minutes. Following up on Nick's last point, and David, you sort of invited the question.

I'm going to take up the challenge here. I believe you indicated, David, that you don't agree that prices need to be passed through to retail customers to do demand response, and I would say I would agree with that as well.

I think it's not necessary, but I think it may not be sufficient not to do so, and I agree with you also Nick, that we do need to do R&D here. We need to move forward, but I think we need to move forward on two prongs.

With that David, as far as how New York does it, I understand it. They don't send the price signals through, but what they do do is allow end use retail customers to participate in the wholesale market, and they're actually paid for their participation, right?

MR. PATTON: Correct. There's a critical difference there, by saying retail customers have to see the wholesale price. What most people are saying is you have to talk the state commissions into changing how they regulate their retail customers.

Trying to get the consensus on that is virtually impossible. What you can do is what New York does. You're going to talk the state commission into changing how they regulate retail customers.

Like I said, we're going to implement settlement rules and we'll pay you the wholesale price is you curtail. People will make noises about that being a subsidy and so forth. The reason, if you construct it right, that it's not a subsidy, is the utility serving that customer is getting a windfall when they don't produce or when they don't consume, right?

So if you pay them the wholesale price when they curtail and you allocate that cost to utilities serving that customer, essentially you just made visible the wholesale costs to that customer, without having to change how they're regulated.

The cost allocation portion of that is pretty important and New York doesn't exactly do that. They have a more shared cost allocation, and I think the economics work right, as long as you're not paying someone who is not under a fixed regulated rate.

MR. BROWN: I think also in New York, they had to get the New York PUC to agree to that, did they not?

MR. PATTON: It's always a good idea to get the New York PUC to agree. Frankly legally, I don't know. The emergency demand response program is one. The second response program is the SEI program in the capacity market, where demand response resources can be paid a capacity payment.

Both those programs are regulated by FERC. I don't know it's necessarily the case that the state commission had to agree to that. There might be some restrictions on what customers can do.

COMMISSIONER WELLLINGHOFF: My concern is I understand that in the Midwest there are certain states that allow customers to participate in programs that the MISO may construct through demand response, and there's other states that may not. That's what causes the disparity.

What I'm suggesting is wouldn't it be better if all the states allow them to participate?

MR. PATTON: I think it would be easier to them into that then having them change how they price retail electricity.

COMMISSIONER WELLLINGHOFF: Exactly. Thank you.

CHAIRMAN KELLIHER: Commissioner Kelly.

COMMISSIONER KELLY: Just to follow up on that, I think we've been talking about the technology. That's one of the exciting things about it, that we don't even really know where it's going to go. It doesn't have price to devices. It could what Yakout was talking about. It could give you real signals.

You could have it set up to respond to variations in wind, and it would be automatically implicated as a demand response measure. You could use demand response to back up your renewables. Maybe I should then ask this panel what I asked the earlier panel.

If you all have a point person on Smart Grid technology that you'd be willing to identify for purposes of the FERC-NARUC's collaborative on Smart Grid, because they're excited about talking to you about how the RTOs are looking at Smart Grid and technology, and ways to integrate it, I sure would appreciate it and NARUC would appreciate it.

MR. BROWN: I'd be happy to.

COMMISSIONER KELLY: Thank you. Is there anything we can do to help you with transmission expansion cost allocation?

MR. EDWARDS: Commissioner, as I said, that is a contentious issue.

(Laughter.)

MR. EDWARDS: We have, we'll be starting a stakeholder process. We have already started internally developing how we're going to do that. It's got to start with the stakeholders. We have some initial faults. We do have some cost-sharing in place now.

It seems like none of the market participants like what's there, but none of them also have any alternatives, other than a couple have said let's do everything postage stamp. So we've got to start with the stakeholders, not the state regulators. We've got to start there.

Without their buy-in, we're dead in the water. If you have any thoughts, I would certainly be glad to hear them. But we will keep you apprised of our progress as we go forward.

COMMISSIONER KELLY: Thank you. The same for you Nick? Do you have a stakeholder process in place?

MR. BROWN: Absolutely. It would be utilized extensively in the development of the cost allocation for our balanced portfolio. I really think one of the gems of the process that came out after an awful lot of thought and debate was on how to balance the portfolio of transmission projects that would be built for these economic reasons.

One of the ways that we achieve the balance that I think will respond to some of the opposition that we've seen on this large build-out of an interstate highway system by some participants who have said "Well, I've already made that investment, and nobody helped me pay for that. Why now are you going to ask me to pay for what's needed in other parts of the country that had not previously made that investment?"

The approach that will be presented for your consideration will actually take revenues out of zones where no facilities are identified as being needed, and roll those into the region-wide rate, to create the balance.

So companies who had made that investment previously and who as part of a balanced portfolio would not be called on to add incremental facilities, and the ability to lend some of the investments to the region-wide rate.

Again, the whole purpose for this is not to equalize everyone, but it is to at least hold everyone harmless to create at least a unity benefit to cost ratio, so that there's something in it for everyone. It literally becomes a win-win situation.

I'm hopeful that that type of thinking, once we get through our process, can maybe be shared and considered by other folks.

COMMISSIONER KELLY: Are you finding within the states where TOs are located in SPP, that there is significant interest in producing renewables for economic development purposes say? If so, is that a possible avenue to get acceptance of transmission-building and cost allocation?

MR. BROWN: Clearly, that was a driver in our region. Many of the states look at wind as a product to be exported. You know, the key is we, as you saw from our queue size, can't consume the magnitude of wind that can be produced in our footprint.

Then the question is are there loads outside our region that want it? I personally can't answer that question. Oddly enough, within our footprint, we only have one state that has a renewable portfolio standard. The others have not gone down that road yet.

But there are tremendous wind resources in our footprint, and there is a strong desire to build transmission to aid the delivery of that resource.

COMMISSIONER KELLY: We have to figure out a way to get that transmission line to California.

(Laughter.)

COMMISSIONER KELLY: Thank you.

CHAIRMAN KELLIHER: Commissioner Moeller.

COMMISSIONER MOELLER: Thank you, Mr. Chairman. First, some comments, and then a general question. But I think it's worth remembering that both of these markets, led by these individuals, have really accomplished quite a bit in the last few years.

There was a lot of tumult in the MISO region just a few years ago, and I think it's fair to say that things have really calmed down quite a bit. I think we're all the beneficiaries of that.

A lot of people need to be congratulated for doing that, and there's a lot of work to go. But I think it's worth noting.

Similarly, I was frankly delighted to in Austin earlier this year at the SPP board meeting, where the RSC report was adopted by the board, to essentially go with a postage stamp rate for economic upgrades.

To me, it doesn't really matter what cost allocation scheme somebody brings to us, as long as transmission gets built. What I really like about that plan is I think it's going to result in a lot of transmission being built. It's going to be good for the region. It's going to be ultimately good for the consumers, and I'm hoping that folks in the MISO can look at SPP as potentially a footprint.

The question I have though for, I guess, all four of you, but mostly for Mr. Edwards and Mr. Brown, is the point of interregional cooperation, and the need for us to perhaps enhance that dialogue a little bit.

I'm going to take it as a personal priority to help that along. So if you have thoughts on how we can do that, first of all, I'm open ears, but I'd like your thoughts right now.

MR. EDWARDS: First of all, Mr. Moeller, interregional coordination planning is critical. I think you're going to hear from all of us today. We do regional planning. We need to do better planning with SPP, with PJM, with New York. All of us need to do better planning.

From our perspective, it's incumbent on us as RTOs to make that happen. I don't think we need to be forced to do it. I don't think you should require us to do it. I think it's incumbent on us.

As I said early on in my comments, we can be a solution to the issues and problem that we face. Part of that solution is interregional planning that we talked about. We've got to get steel in the ground from the transmission standpoint. If we're willing for development to come about, the way that some are predicting, we're talking about major investments in transmission.

Early on, I made the comment that there are 69,000 megawatts of wind in our queue right now. We have done some studies recently that said if the scenario, if 40,000 megawatts of wind are constructed within our footprint, that would take about $30 billion of transmission investment to move that to load centers to be utilized, two-thirds within our footprint and one-third for those folks to the east and south of us.

We're talking about major investments here that impact not just the one RTO. It impacts many different regions. So getting back to your comment, interregional planning, planning among the RTOs is more critical, even more critical.

MR. BROWN: We see the same numbers in our footprint. In fact, the EHDO released a study that we have given you a visual perspective of. If memory serves me right, I think the input data for that only contemplated up to 20,000 megawatts of wind. I could be wrong. Don't hold me to that. I'll send you the actual numbers.

Again, that also contemplated $6 billion of investment just within the SPP footprint. It would accommodate only 20,000 megawatts of wind. So Graham's exactly right. If this nation is going to harvest that resource, it's going to take major investment to make it happen.

COMMISSIONER MOELLER: So Nick, you alluded to the fact that we may need to be a little more active. Graham, you said you'll do it yourselves. Do you want me to show up at an RTO Council meeting? What can we do to make sure this gets going?

MR. EDWARDS: Commissioner, I have heard your message, and we have heard your message on several fronts. Even the previous panelists have heard various messages on issues you all have brought up and addressed.

Again, I think it's incumbent on us to be held accountable to do that, and to make those things happen. You've got my commitment, and I'm sure Nick and I will do our best within the IRC Council, to ensure better planning, individual planning, and I think we can talk more about process initially than anything, because the numbers will fall, the plan will be developed.

We'll be talking about process. We'll be doing a lot. We're taking it on our action item list, and we'll make it happen.

COMMISSIONER MOELLER: Thank you.

MR. BROWN: I really think it comes to sharing information and data. When we began our process, the opinions were very diverse. If you had asked me two years ago if we'd end up with a full postage stamp rate for even a balanced portfolio of economic upgrades, I would have said no, it's just not going to happen.

But as everyone got together and met and shared the information, and commonly developed a vision for the future, not only for one of our states for the SPP region but for the nation as a whole, it became very, very clear what the right answer was, at least for us.

Maybe that's not the right answer for the whole nation. I won't try to prejudge that. But I am convinced that is an answer that's better than what we've got today, which is no interregional cost-sharing.

COMMISSIONER MOELLER: Thank you. Mr. Chairman.

CHAIRMAN KELLIHER: Thank you. I don't know whose phone that is.

COMMISSIONER MOELLER: Somebody who wants more transmission built.

(Laughter.)

CHAIRMAN KELLIHER: A couple of questions. First of all, Graham, I really like the way you described the benefits of MISO, both the ones that are quantitative and qualitative. Among the qualitative benefits, you pointed out transparency, and I think that really --

I agree. I can't put a number on it, but if you can contrast the current situation from the summer of '98 and '99, when there were price spikes in the Midwest before there was a Midwest ISO and prices reached five or seven thousand dollars a megawatt hour, and FERC did a report on one of those price spikes, and someone, one of the buyers, was asked "Why did you pay so much?"

He said "That's what the guy on the other end of the phone was asking for." The market was totally opaque, and there was no way they would figure out what the price of power was unless they called 100 or 200 or some statistically valid number.

So they paid five or seven thousand dollars or something like that. There's mystery to what the price of wholesale power is in the Midwest is now. There's a huge change and a huge benefit, one that doesn't lend itself to being quantified.

So I'm glad you pointed that out. But I had just a question for Nick. In SPP, $2.2 billion, what does that represent compared to your current transmission asset base?

MR. BROWN: Oh gosh. Within the whole footprint? That's got to be pushing 15 percent.

CHAIRMAN KELLIHER: That's pretty significant.

MR. BROWN: The thing I want emphasize, and

Richard alluded to it in his presentation where he just came out and said it, the aging of our current infrastructure is a problem that we're only now coming to grips with.

CHAIRMAN KELLIHER: And you're talking about transmission as well as generation?

MR. BROWN: Right now, I'm only talking about the transmission. But the aging of the generation fleet is also very concerning to me. I don't have the numbers at my fingertips right now, but I have done research on aging of the generation fleet.

Something like 15 percent is past its useful life, in terms of depreciation, and most of those are on 40-year depreciation cycles. So 15 is older than 40 years.

So the whole aging has raised the concern, in my mind.

CHAIRMAN KELLIHER: There's been a lot of discussion about wind and the extent and size of wind development. What is the market the wind developers are looking for? It doesn't seem they're looking at the interconnected utility, just given the scale. So they're not looking at the local utility.

Are they looking at the regional market, or are they looking beyond the regional market, the development of MISO? Are they looking at MISO as the market? It's not looking the market. They say that, but is it MISO? Is it

MISO plus PJM? Is it perhaps New York?

MR. BROWN: The answer is yes.

MR. EDWARDS: I think the situation is based on the size of the footprint, where most of the wind generation is. Some of the utilities have mandates by their states, as well as additional imposed mandates on the utilities.

Specifically, they're doing it to meet those mandates, but also meet the requirements for their own load, and also to sell them into the marketplace where they can, when the prices are right.

I think the answer is yes to all those issues, Mr. Chairman.

CHAIRMAN KELLIHER: Nick, the same is true in SPP?

MR. BROWN: Absolutely.

CHAIRMAN KELLIHER: You made the point, I think, and the panelists this morning made the point that it isn't just an accident that this development is occurring the organized markets.

I can't remember if it was New York that said that 73 percent of the development is in the organized markets, and they had 44 percent of the capacity. So it doesn't seem to be an accident.

The other point that I think Terry made, there hasn't been good modeling on how the power flows might change under the climate change scenario in your two regions that right now could be totally dependent on coal. There's also regions heavily dependent on coal and a lot of wind development being proposed.

But looking at a lot of gas generation being built, you know, over the next ten years, how differently might your grids be operated if we actually do act on climate change? Also, there's not -- I'd assume there's not nuclear development in the next ten years. You see a good amount of wind development and heavy reliance on gas.

MR. BROWN: Maybe it's that uncertainty that is the exclamation point on the need to built out the transmission system, to a much more robust stance that it is today.

That's what affords the options. When we look at the number of issues we've talked about today, they are numerous, they are complex, and there's a large amount of uncertainty with each one of those issues.

In my mind, that just begs for a portfolio of solution approaches, but also one that is primarily focused on deliverability. That's what transmission affords, the deliverability from any number of options, because I can't read the tea leaves on a lot of those issues.

So we need to keep everything on the table, all options on the table, and it just begs for the interstate highway system that affords deliverability of any number of generation resources.

MR. EDWARDS: I agree with Nick that a robust transmission system is an enabler to deal with a lot of these issues we're facing.

Another concern I have, is the ability of available resources, the impacts they have on systems, how do you follow that, how do you manage that from a systems standpoint, from a regulations standpoint? How do you back it up, and all those issues I really don't think we addressed yet.

In addition to carbon, how do we start economically dispatching the systems? That is a massive change to what we're currently doing, if you have to do that.

So, there are major issues here that we've got to solve, in addition to transmission.

CHAIRMAN KELLIHER: If I'm hearing you, you're saying we need a grid that can operate reliably under a number of different scenarios. We can't predict the future, and we need a grid that can really survive a number of different outcomes.

Great, Commissioner Spitzer, perfect timing.

COMMISSIONER SPITZER: Thank you. I apologize for being absent. The Chairman noted the wind in the queue is disproportionate, relative to particularly SPP, so I'm assuming this is based upon -- these developers are basing it upon export outside of SPP.

MR. BROWN: Very much so.

COMMISSIONER SPITZER: That's part of your deliverability option you were discussing for the transmission grid. You know, I just happened upon, briefly, a press clipping from a newspaper to your east, that said that deregulation has failed; we need to get rid of it and go back to the status quo.

Presumably, that would obviously run directly contrary to the concepts of the renewable resources being exported to the east. If the utilities go back into the generation business and recreate the vertical monopoly, that would be the case, would it not, and that illustrates, I guess, the fact that we're dependent upon regions outside our own. What advice would you have to those who are, frankly, under this great political pressure to the east?

Secondly, we got into this carbon discussion. There is a lot of uncertainty, but I do sense from the Congress, a recognition of the great complexity of the matter, and they've sought out advice, and to the extent advice has been sought from you, what would your recommendation be in terms of crafting, assuming there's going to be a solution crafted, how would you implement it and enforce it?

MR. BROWN: Let me tackle the second question, first. I'm still thinking about an answer to the first, and advice. I will be participating in a conference hosted by Congressman Mike Ross from Arkansas, later this month, so I have formulated a few thoughts, but, quite frankly, they echo what I've shared here today.

The issues facing our nation, from an energy policy perspective, are numerous, they are very complex, and there's a high degree of uncertainty associated with all of them. So we don't need to take any options off the table.

That means we need more technology, we need more options. That's what technology can produce.

We need to address aging infrastructure, both on the transmission side of the equation and the generation side of the equation. Obviously, as we've talked about greenhouse gas, what is going to come about in that regard?

I, for one, looking at the capacity needs, just cannot see us taking coal off the table, which has happened within our footprint, on two separate occasions within the last year. Large baseload units, economically very justifiable, but because, I think, of misinformation in terms of how they would fit in and some fear that they were competing with renewable resources, which, in reality, at least one of these units would have facilitated more reliable operation of renewable resources within our footprint --

COMMISSIONER SPITZER: To be fair, those decisions were in the siting process, as opposed to a regime of cap-and-trade, so it was sort of an ad hoc siting decision.

MR. BROWN: I understand. I think the question was, what would I recommend in terms of national policy? And it's to keep everything on the table. Short and sweet, we need to be adding ideas to the table, not pulling ideas off the table, and, again, reinforce the need for a very robust transportation network that affords us to take advantage of all of these very diverse and numerous portfolios of resources.

MR. EDWARDS: Commissioner, if I may, just in response to the issues, there are comments, accusations, that competition, deregulation, quote, "is not working." I would put forward that the wholesale competition is working, and I think it's been demonstrated.

So my comment would be that I think it's a wholesale versus a retail issue, from that debate perspective. I think that is part of the issue that we see in the trade press, being debated before state commissions, before this commission, before Congress, and before others.

Let's don't confuse wholesale markets with retail markets. I think there's a distinction. The wholesale markets are working.

CHAIRMAN KELLIHER: One last question, just of Nick in your EPRI role. If you could pick a technology out of the ether and make it commercially available, which would it be? Which technology breakthrough would most help the delivery of reliable electricity at reasonable cost? Is it carbon-capture and sequestration, transmission technology, storage? What's the holy grail for us?

MR. BROWN: Therein lies the challenge. You know, as Graham said, yes, we really need all of it. EPRI worked very, very hard on the portfolio approach that they have laid out, in terms of responding to global warming.

Sequestration clearly is needed, when you look at the tremendous coal resources in this nation, but, at the same time, if you take any of those other options, including plug-in hybrid vehicles, the smart grid to enable that, they all fit like this.

Quite frankly, if you take any one of those off, you do, I think, great damage to the total picture, because they are that interrelated.

A lot of thought from a lot of very smart researchers, went into putting that portfolio approach together. I, for one, am just elated with the work.

Through the peer review, that has been nothing but supportive. I've not heard anyone challenge the assumptions made.

Here's a key point, too: Even when you look at that portfolio of options and projects that EPRI has put on the table, they are all aggressive. They're doable, they're achievable, but they're all aggressive.

It's going to take a bigger commitment than we as an industry have put toward it today.

CHAIRMAN KELLIHER: I like the Prism Study, but it is bracing to think that, at some level, we're assuming that we're going to turn the table on technology development, that we're going to have uniform success in a number of fronts. That almost is a necessary condition to address climate change at reasonable cost.

I'm not sure we can assume that, but I'm glad you're working on that.

MR. BROWN: It will be a challenge.

CHAIRMAN KELLIHER: Any other questions, colleagues?

MR. EDWARDS: If I may just say thank you very much for taking your time and being attentive during this process. It's been a long day, but I appreciate it very much. I think it was very important to go through it, and I want to say thank you.

CHAIRMAN KELLIHER: Thank you very much for helping us today. We'll now turn to our own Charlie Whitmore.

COMMISSIONER MOELLER: On the technology issue, I'd just say, wireless electricity will help a lot.

(Laughter.)

COMMISSIONER MOELLER: Nicola Tesla is not returning my calls.

(Laughter.)

(Slide.)

MR. WHITMORE: Mr. Chairman and Commissioners, good afternoon.

I'm here today to present the Office of Enforcement's view of electric power markets outside the RTOs, that is, in the West and the Southeast.

This presentation will be posted on the Commission's website today.

(Slide.)

MR. WHITMORE: This slide highlights the Southeast and the West, outside the Cal ISO. Together, these regions account for about 40 percent of total load and total generating capacity in the United States.

The non-RTO West also accounts for a large proportion of the nation's potential energy reserves. Both regions use bilateral electric power markets and depend on them for crucial aspects of their functioning, but the nature and role of the bilateral markets, differ substantially between the two regions.

(Slide.)

MR. WHITMORE: We've heard today from the Market Monitors for the RTOs. Outside RTOs, the challenges of monitoring markets, are different and, in some ways, more difficult.

In bilateral markets, participants can conclude deals on many different platforms. Much of the information in this presentation, comes from the Intercontinental Exchange, ICE, because it's a major trading platform that we have a lot of information from.

But market participants can as easily use an array of voice brokers to make deals, or they can talk directly to possible counterparties.

In short, in non-RTO regions, there is no central market institution to serve as the primary focus for market monitoring, so the strategies for monitoring these markets, must be different.

The Commission currently oversees the bilateral markets in three main ways: Individual company reports, responses to complaints, and internal oversight efforts.

The first two approaches address possible abuses of transmission by individual companies. The third seeks to understand how the larger regional markets work.

We receive formal market reports from six individual companies. Five have individual company monitors, Potomac Economics, in all five cases, and I suspect that David needs five more ties or six more ties for that.

Four of these are in the West or in the Southeast -- Arizona Public Service, Pacificorp, Public Service Company of New Mexico, and Duke Energy-Carolina.

Potomac Economics submits a report on each company, four times a year, focusing especially on the company's use of transmission. This provides reasonable assurance of the good behavior of each company, but does relatively little to help us understand the larger regional market.

Also in the Southeast, Entergy uses SPP as its ICT, the Independent Coordinator of Transmission. The ICT is not a market monitor in the usual sense, but it does provide quarterly reports on the operation of Entergy's system and its development of a procurement process.

The Commission has an extensive system of accepting and responding to complaints. These can come from the Hotline or from Section 206 complaints, and we take care to respond to all of these complaints in an appropriate way.

These are effective at remedying specific problems that arise in both RTO and bilateral markets, but, by themselves, provide an incomplete picture of the overall performance of such markets.

The Division of Energy Market Oversight oversees the broader functioning of the Western and Southeastern markets. Much of this oversight comes from examining a wide variety of data sources.

Two of the most important are ICE and the Electric Quarterly Report, the EQR, and you'll see examples of both today. We've also begun a pilot project with the Southern Companies, to help us understand how the Southeastern market works better.

Southern volunteered to visit us periodically. They now are coming three times a year to provide its perspective on how the Southeastern markets work.

The conversations so far, have covered everything from showing us the hours in which Southern either bought or sold power during a recent period, to describing the Company's view of coal markets.

I want to commend Southern for voluntarily entering this effort. The conversations have been open and we've been free to discuss almost anything.

Nonetheless, we understand that no single company provides a full view of the market, nor do we expect its view to be disinterested.

We hope that other companies will join Southern in improving our understanding of how markets work in both the Southeast and the West.

Let me quickly mention in this context, that we also talk with state commission staffs in both regions, in conference calls each month. Those calls have already provided us with an important additional point of view in both regions, and we're grateful to the participants in both calls.

(Slide.)

MR. WHITMORE: Bilateral markets have a mix of both long-term and spot transactions. Today, I'm going to focus mostly on the spot transactions, both to make the focus consistent with most of the reports that RTO Market Monitors do, and because the strongest differences among the markets, show up in the way the spot market operates.

As we'll see, however, spot markets are a relatively small part of the overall wholesale market in the Southeast. A major focus for us, going forward, will probably be on longer-term transactions, at least in that region.

This year's State of the Market presentation provided the highest-level description of the differences for the West and the Southeast electric market regimes in the United States.

This slide shows transaction volumes from ICE, which provide the clearest view we have into the day-ahead and intraday bilateral trading, which is what I'm calling the spot market.

This slide shows only those spot transactions, though, of course, ICE does accommodate longer-term transactions, as well.

To review, in regions where RTOs have day-ahead markets, bilateral spot markets act primarily as intraday financial derivatives of the prices RTOs produce.

The RTO prices are the standard benchmark for day-ahead value, and the bilateral spot market becomes a way for market participants to tweak their positions during the day.

In the West, bilateral spot markets are far more important. Spot physical transactions account for more volume in the West, than in any other region of the country. In fact, the bilateral spot market appears to be playing some of the same role in day-ahead price discovery in the West, that RTO markets do in the Northeast and Midwest.

Of course, the RTO day-ahead markets are much more complex and differentiate much more strongly among locations and timing during the day, but for basic daily evaluations, the two systems seem to fill similar niches.

For Western spot markets, the financial instruments are unimportant. In the Southeast, bilateral spot markets are much smaller, at least according to ICE data. They are entirely physical and less than 1/40th the size of their counterparts in the West.

The Southeastern spot markets appear to be a residual market for small amounts of power traded after the integrated utility has handled most of their own loads.

It is unlikely that they serve a major price discovery role in the sense of providing prices that people would invest on or something like that.

The spot markets are simply too small, overall. Nonetheless, bilateral spot markets are important at the margin in the Southeast, and can become quite important during periods of system stress.

(Slide.)

MR. WHITMORE: The routes of western power markets, reach back into the 1930s, with the development of very large hydropower reserves in both the Pacific Northwest and, somewhat later -- actually at the same time, in the Colorado River Basin.

As demand in California grew, the need for long distance transmission became clearer and clearer, and as the slide shows, the first major intertie from the Pacific Northwest to California, dates from the 1970s.

Thereafter, the West became an increasingly integrated electric system, dependent on moving large quantities of bulk power over large distances.

As a result, when electric markets became possible toward the end of the century, the West had a very large commercial need to develop ways to trade power over long distances.

At heart, that remains the basis of today's western bilateral power markets.

(Slide.)

MR. WHITMORE: Western power markets still display considerably different valuations from power in different subregions. This slide shows the difference in valuation by month among the Northwest, California, and the Southwest.

The differences in value, are particularly important for the Northwest, where the availability of hydropower is not entirely predictable over the long run, and where hydropower plays a major role in determining what power is available for trade and at what prices.

I'll just mention here that over the last month or so, we've seen frequently negative prices, off-peak, in the Pacific Northwest, which is kind of an ultimate test of how different prices can be, given natural gas prices in California.

There are also significant differences between California and the Southwest. Market participants need ready access to markets where they could arbitrage the differences and make power move from areas with fundable cheap supplies, to areas where it's more valuable.

COMMISSIONER KELLY: Charlie, can you go back to that slide and explain exactly what we're seeing there?

MR. WHITMORE: SP 15 usually has a higher price than the other areas. So SP minus Mid C is the blue line on the chart. You'll see it's often quite a bit higher, even averaged over a month.

SP 15 minus Palo -- that should be Paloverde -- it's generally higher. But it's not as much different as it is for other northwest.

COMMISSIONER KELLY: Are you tracking these? Are these average?

MR. WHITMORE: They're average for the month.

COMMISSIONER KELLY: Every month is on here?

MR. WHITMORE: Every month is on here going back to 2002.

COMMISSIONER KELLY: Thank you.

MR. WHITMORE: I apologize for the lack of clarity.

(Slide.)

The trade press began to report prices for western electric spot markets in the 1990s. By that time there was a compelling commercial need to create such markets and report on them. In this respect they resemble the natural gas markets that emerged slightly earlier for similar reasons.

As with the natural gas markets, western spot electric markets differentiate the most commercially-available price differences. This slide shows that the largest spot trading occurs in four places: Mid-Columbia in the northwest, NP 15 and SP 15 in California, and Paloverde in Arizona.

Several other points -- the California/Oregon, the Lake Mead and Nevada, and Four Corners in the southwest, are also significant spot trading points. Each trades peak and off-peak power.

Those who are used to RTOs will find these distinctions rudimentary compared with the hourly prices that are available from thousands of nodes in RTO markets. Western bilateral markets simply do not reflect the detailed differences of valuation that are a hallmark of RTO markets. Nonetheless, the western markets do reflect the most important differences in commercial value for both location and timing. They also provide specificity and convenience at relatively low cost.

The point is not that one model is inherently better or worse than the other. Each grew up in a different historical context, and each serves somewhat different functions.

We've heard today Cal ISO expects to implement MRTU in the fairly near future. If the western experience follows precedents from the east, the existence of an ISO day-ahead market will change the nature of the bilateral market in the west. In particular, Cal ISO's day-ahead market is likely to become the primary pricing vehicle for spot power transactions within California, replacing the function for the current bilateral market plays at SP 15 and NP 15. It's less likely to displace the price discovery points function for points that often show quite different prices from California, for example Mid-Columbia.

(Slide.)

Market participants also trade long-term power in the west at least on ICE. The physical size of the long-term market is relatively small compared with both the physical spot market and the longer-term financial markets. Long-term physical ICE deals are most prevalent in the northwest, of course. There are also many company-to-company long-term contracts that don't use ICE.

The bulk of long-term western trade on ICE occurs financially. As is true of many commodity markets, this financial trading dwarfs the related physical trading, and it is very heavily concentrated in SP 15 and to a lesser extent Mid-Columbia. This also is consistent with many financial commodity markets that tend to concentrate on a small number of delivery points.

Synergy Hub, NEPOOL and PJM play a similar role in long-term eastern financial markets. In the case of the west, it makes sense to concentrate on SP 15, the largest consuming area in the region. However, the long-term prices are similar between Southern California and the desert southwest, and the differences are fairly predictable -- that is, it makes sense to arbitrage the California-southwest price differences in the daily markets, but not so much in the longer-term markets.

It also makes sense that there is a considerable long-term activity in the northwest. There prices can be quite different over the long term from prices in California.

(Slide.)

On this slide, this should be western generation.

COMMISSIONER KELLY: Charlie, can I ask you just a clarification? What's going on here? Is this hedging?

MR. WHITMORE: Probably.

COMMISSIONER KELLY: Why is SP 15 and NP 15 the two biggest ICE spots physically? Why is NP 15 not so big as SP 15 in the long-term financial? Different markets?

MR. WHITMORE: What very often happens in financial markets, especially longer-term, is that people will focus on one pricing point and run everything off of that.

COMMISSIONER KELLY: Who would be the customers there, the geographic location of them? It would be the entire west?

MR. WHITMORE: Probably everywhere in the west outside the northwest. And the key difference there is that in the southwest, probabilistically, prices are going to track California's over time, and so you can hedge Paloverde over the long term by buying and selling at SP 15 and having some kind of differential.

Mid C in the northwest is different, because hydro is different every year. You have different risk factors involved there, and the price can be radically different. The difference between the two can be radically different from year to year, so you might well want to hedge Mid C separately from what you're doing in California.

COMMISSIONER KELLY: Is the advantage of choosing one hub, of having trades go to one hub for the long-term financial, is that liquidity in one or is it cost?

MR. WHITMORE: It's probably primarily liquidity. Traders like to be able to trade in and out. Once they gravitate toward a point, then it tends to be a winner-take-all situation. It's not unlike what happens at Henry Hub, where you get so much trading, even though you have to do lots of things to hedge the rest of the risk.

COMMISSIONER KELLY: Thank you.

(Slide.)

MR. WHITMORE: This slide should be Western Generation Addition rather than Generation overall.

Another key aspect of longer-term markets is the amount of new investment taking place.

CHAIRMAN KELLIHER: This is outside California, Charlie?

MR. WHITMORE: Yes. In fact, the slide shows the amount of new generation coming on line in the west outside California since 2000.

As with other regions, there was a large burst of new capacity early in the decade. We'll see it even more exaggerated in the southeast. Almost all of it was fired at that point by natural gas. Since then, the region has continued to build a significant amount of new capacity, but with a greater diversity of energy sources, although the majority of capacity additions are still gas-fired.

Wind has become much more important. There are also some coal additions. In any case, the NERC reports that reserves are adequate now, and projects they will remain so. This is not a bad performance at all in the west.

(Slide.)

At the risk of going out on a limb, I will maintain my own personal view at least that the largest strategic challenge facing the west ultimately is how to make use of the energy reserves in the Rockies. The states of the northern Rockies -- Wyoming, Montana, Colorado and Utah -- have vast stores of potential energy: coal from the Powder River basin, other deposits of natural gas, especially from Wyoming and Colorado, and wind that blows in abundance. And anyone who's spent time in Cheyenne can understand that.

If the hallmark of western electric markets so far has been the ability to support commerce over wide distances on the west coast and the southwest, the next challenge will be whether the markets can support the development of the infrastructure needed to get Rockies energy to market. Market participants are working hard to create the infrastructure that will be needed to bring Rockies energy to market.

In the case of natural gas which is up there now --

(Slide.)

-- they recently completed building Rockies Express to the midwest, and have a variety of projects to build more pipeline capacity in the next few years. In that connection, I'll just mention that over the past month or so, the prices in Wyoming have again begun to fall, because Wyoming has already grown into the Rockies Express capacity, and they will again face the same kind of problem they had last year very shortly.

So the fact that there are more things on the drawing board and coming on line in the next few years is very important on the gas side. If for some reason electric transmission didn't get built, you would in effect be doing power by pipe from the Rockies.

(Slide.)

For electric power, there's been relatively little expansion in the region for the transmission grid so far. But there are many proposals at various stages of development, and my understanding is, there's a highly concerted effort in the US to do regional planning that would get this done.

But there are slips, obviously, betwixt cup and lip. So far there has been relatively little spot trading at any point in the Rockies. But if the west succeeds in connecting electric power resources in the Rockies with the consuming market, that's likely to change. In the absence of an RTO in the region, western bilateral spot markets would then be likely to provide price discovery for that subregion as well.

(Slide.)

Turning to the southeast, southeastern power markets also have their roots in earlier times, beginning in the 1960s and especially in the wake of the New York blackout of 1967. The southeast began to build out its electric transmission grid. The slide shows that many of the transmission lines connected large generating plants to each other. This was primarily to insure reliability, but it also had economic consequences.

One key is that it allowed companies to share reserves better. If a company was building a nuclear plant, for example, it was much cheaper to rely on its neighbor's nuclear plant for reliability, rather than having the company itself build two of them, especially given the costs some of us remember in nuclear plants in the region.

The result was a gradually more integrated transmission grid that enabled reserve sharing, and it also made possible more economy transactions -- that is, small trades of power at the margin that could cut costs for both sides.

The second impetus for markets in the southeast, actually for transmission in the southeast, was the need to meet Florida's demand for power. These days we tend to think that there's not all that much transmission into Florida. But if you look back 30 or 40 years, that was a big deal to get transmission into Florida.

Through the 1970s and '80s, the region built transmission lines to deliver coal by wire into Florida -- essentially the same logic that compelled the long-line transmission lines in the west. However, the electric links between Florida and the southeast remain relatively small, and have not provided the same basis for a large bilateral spot market.

(Slide.)

The state of the markets presentation reported EQR data for Southern Company. During normal times, EQR reports confirmed what Southern had told us: that they normally bought or sold less than 1 percent of their overall supply on spot markets.

EQR also confirmed that spot markets were more important during stressful periods. During last August's heat wave, Southern spot purchases rose above 5 percent during the afternoon peak hours on most days. This highlights the importance of the spot market to meet unusual peaks, at least for Southern.

(Slide.)

Long-term energy transactions are a hallmark of the southeast. Preliminary analysis of EQR data suggests the jurisdictional sellers in the southeast sell far more power under contract than they do through spot transactions. Many, certainly not all, of the long-term sales agreements in the southeast take place under either full requirements contracts -- typically between large utilities and smaller, publicly-owned utilities -- or long-term purchased power agreements, typically between independent power generators and the utilities.

In both cases the contracts are usually isolated from long-term price risks, except fuel costs. That's the likely explanation of the fact that there is no financial trading of power, long-term or short-term, in the southeast. If the market participants want to hedge their fuel price risks, they can do so directly in natural gas or coal markets, and there's relatively little reason for a separate hedge for power.

To the extent that requirements and purchased power contracts are prevalent in the southeast, it would suggest that the most important point for potential competition in the region would be at the stage when a plant is being planned, not after it's built. I'll mention an example of such competition in a moment.

(Slide.)

Generation in the southeast, and this again should be additions to generation in the southeast -- in the early part of this decade, the southeast invested heavily in natural gas plants. Indeed, most observers would say that the region overinvested in them, and a number of companies felt the sting of that through the decade.

In any case, the region's been growing into that capacity in recent years, and has added relatively little new generation through 2003. Going forward, there seems to be an increased emphasis in the region on building new baseload capacity, including Plant Vogel, a nuclear plant proposed in Georgia, and the Sumner plant, also a nuclear plant proposal that's in South Carolina.

In any case, NERC projects that there are adequate reserves today, and reserves will remain adequate in the future.

(Slide.)

Probably the greatest challenge in understanding power markets in the southeast is the lack of visibility in how the systems are operating. Please note that I didn't use the term, transparency, in this context. As we learned in talking with the Southern Company, there simply is not that much of a spot market to see.

For example, Southern itself is active either buying or selling in hourly spot markets only about 30 percent of all hours, and they're not a small company in the region. In effect, there just aren't very many spot market transactions to see, at least judging by Southern's experience and ICE data.

Florida provides a particular challenge for market oversight. ICE reports no electric power prices for Florida. The trade press does report one spot electric power price for Florida, but on most days those prices rest on no reported volumes. In practice, Florida is far more completely integrated into the nation's natural gas grid than into its electric grid.

Our best indication of the marginal costs of power in Florida may well come from natural gas reports. Bentek Energy monitors delivery of natural gas to many electric plants around the country, including in Florida. The slide shows how much gas was scheduled to natural gas plants in Florida, and how often the gas was scheduled to more costly gas turbine units during the second half of the year. This shows at least when gas peaking units were probably running, and when they were not, and provides a first step in understanding the marginal cost of power each day in Florida. I should mention in this regard that a fair amount of the time in Florida, oil is on the margin, and as you may recall from our last conversation, oil adds a significant kicker to costs above even the most expensive gas plants.

In Florida, and to a lesser extent the whole southeast, spot power markets are simply not active enough to be a primary indication of how the broader wholesale market is working or likely to work. We need instead to work creatively with other data sources to gain the kind of understanding that spot markets convey elsewhere. Hence our efforts to get in contact with companies and learn more from them directly.

(Slide.)

The southeast is not generally known as a hotbed of competition for the electric power industry. But states have taken opportunities to use competitive forces to the advantage of their ratepayers, especially for long-term decisions. Georgia may provide the two best examples in that regard.

First, Georgia requires Georgia Power to make almost all of its capacity additions through a competitive procurement process. The process begins with a transparent stakeholder process to determine an integrated resources plan, or IRP. It includes an open process to design a request for proposal. Once competitors submit their bids, an independent assessor judges the proposals. The Georgia Public Service Commission supervises the overall process and makes final decisions.

The Southern Company says that non-affiliated companies have become more competitive with time, and that it expects about half of all the capacity that Georgia Power buys between 2007 and 2015 would come from non-affiliated sources. If realized, this would result in still a quite concentrated outcome, but it's also a far cry from pure traditional monopoly.

COMMISSIONER KELLY: Charlie, do we have any idea how much capacity that's going to be?

MR. WHITMORE: Just a second. I've got a couple of notes here somewhere or other.

(Pause.)

Not exactly on that. What I can tell you is that over the past few years they have added 14,000 megawatts of competitive capacity in the overall Southern control area, of which about 4300 is owned by Southern itself. About 10,000 -- they have a total, probably, of 50,000, 55,000. So it's a piece, neither trivial nor large.

Secondly, the state of Georgia allows many of its publicly-owned utilities to compete with Georgia Power to supply large industrial customers in the state. Partly in response, Georgia Power developed the real-time pricing program I mentioned earlier this year in the state of the markets report, and it's one of the most successful real-time pricing programs in the country. It skipped many additional customers on Southern's system, but it also provided real pricing to real customers, arguably the heart of the market outcome.

And let me, for fairness, add another point from earlier today. We heard a lot of talk about unforced outages in other regions. Southern has a very low rate of unforced outages, below 2 percent, and it's been improving over the years. So without making any more general comment about other companies in these two regions, it is certainly possible to have a good record on that score outside the RTOs.

In any case, I don't want to overstate the case for competition in the southeast. The Georgia examples are not unique, but they're also not common. But I think it's important to understand that there's nothing in the wholesale model in the southeast that prevents the growth of programs like that.

(Slide.)

To conclude, both western and southeastern bilateral markets are important. They work quite differently from each other, and both differ deeply from the RTO markets. In the west, we see a market that used existing transmission resources to develop markets without central direction, roughly along the lines of the natural gas markets. The biggest challenge to this market going forward may be whether it can integrate new resources that will not require substantial new infrastructure.

In the southeast, we see an electric industry that focuses primarily on long-term investment decisions, mostly within a traditional integrated utility framework. And what I mentioned before -- 10,000 megawatts for Southern. They would say: well, yes, but that's a very large proportion of anything on the wholesale markets, because we build so much for our native load and so on.

Spot electric markets in the southeast developed as small add-ons to the basic structure, and appear to be particularly useful at peak periods.

That concludes my presentation. I would like to thank the people in the Division of Energy Market Oversight who helped on this, most extensively Bill Booth and Judy Eastwood, but also Tamara Martin, Tim Shears, Jeff Sanders at the keyboard, and Steve Honeycutt.

Thank you all very much. Questions?

CHAIRMAN KELLIHER: That's a good presentation. I'm glad you did it. It completes our review of most of the wholesale power markets in the lower 48.

You point out just how different the western and southern markets are, both from the organized markets, but also from each other.

I have a couple of questoins, though. Another difference seems to be the grid, the nature of the grid in the South, versus the West.

In the South -- it seems that the U.S. has more than 500 owners of the grid, so you have relatively fractured ownership, nationwide, but, in the South, it's more concentrated. There's relatively fewer owners of large blocks of the grid, whereas, in the West, the Federal Government is a big player and it seems that ownership is a bit more fractured in the West.

The South and the West -- the South is making a lot of investments in transition, we don't know what those investments are. It isn't really distribution, but we consider it bulk power.

MR. WHITMORE: We have, I believe, a study ongoing, looking at what that looks like. I don't know what the results of that will be.

CHAIRMAN KELLIHER: In the West there's a lot of planning about major investments. Pacificorp is making some major investments; otherwise, there's a lot of planning of investments, without the investments quite getting going, it seems.

I had one question about -- an observation rather than a question. In terms of a question on gas, what is being built now in the South? The South relies heavily in gas, as do other regions, in terms of what the increments of new generation are. Is that coming more from gas?

MR. WHITMORE: Going forward, it's a little bit hard to tell. As you can see from the graph -- let me go back here.

CHAIRMAN KELLIHER: I mean, Florida is building gas, and I thought more gas was being built elsewhere in the Southeast.

(Slide.)

MR. WHITMORE: If you look at the graph, what you can see, is that the light beige is gas. It's almost all gas for the last ten years.

There is a little increment of nuclear from Brown's Ferry coming back. There's very little wind. There's a little bit of coal, but, basically, it's been all gas, all the time, throughout the South, in the last ten years.

Going forward, as I mentioned, they're still growing into what they built then, and so there appears to be renewed interest in baseload plants that would perhaps not be gas, but at least for anything that's going to get used anytime soon, it's all gas -- almost all gas.

CHAIRMAN KELLIHER: In terms of who's building in the South, versus the West, in the South, is it tending to be the vertically-integrated utilities, but in the West, is it tending to be the independent power producers?

MR. WHITMORE: The numbers we have from 2001 through 2008, say that in the Southeast -- and this does include that earlier phase of rapid building -- in the Southeast, just about half was utility and 44 percent was independents. Then there's a smattering of self-generation and things like that.

In the West, it's 53 percent independents and 42 percent utilities, something like that, so it's relatively balanced, actually, over the past ten years, in both regions, although there is a tendency, as you say, for more utility investment in the Southeast and more independent in the West.

But there is a significant independent sector in the Southeast, also.

COMMISSIONER KELLY: Were those numbers, the independents who built -- they were independent when they built? Then most of them failed, and there's not many independents in there now.

MR. WHITMORE: That's fair enough. The question is, where did the investment come from? It was largely from the independents. Where did it end up? Well --

(Laughter.)

CHAIRMAN KELLIHER: A couple of banks, too, ended up probably as generators. Colleagues, questions? Do you really want to grill Charlie? We can grill him any day.

(Laughter.)

CHAIRMAN KELLIHER: In private, sometime. Phil?

COMMISSIONER MOELLER: Thank you, Charlie. Your presentation was quite diplomatic and not taking sides on markets or bilateral or organized, but as we did here earlier, at least the wind industry, and, I would argue, probably the renewables industry, prefers the openness of an organized market, because that better allows them to get their products to consumers. Care to comment on that?

MR. WHITMORE: Well, having been assigned to do this at the end of the day, when the CEOs of all of the RTOs were in to talk about their markets, it seems to me that I should be strictly dispassionate.

(Laughter.)

MR. WHITMORE: I think I should maintain that. In that regard, I guess what I need to say, is, if you talk with different customer groups, you'll get different views about which model they would prefer.

While it's certainly true that the wind folks or renewables have a view on it, it's also true that the munis and people like that, have a view on it.

The best thing that I can do, is to try to help understand how the things actually work, and let other people worry about which ones are better or worse.

COMMISSIONER MOELLER: I'm just glad you chose FERC and not the State Department.

(Laughter.)

CHAIRMAN KELLIHER: I really enjoyed your presentation, because if you look at at least what I laid out as what I think are the characteristics of competitive markets, since we're towards the end here, I don't really see that any region has all the characteristics of a perfectly competitive market, and the South and West have some. There's some that they seem to lack, but they have -- they probably have most of those characteristics, so I think you can say they're competitive, with a small C, in the South, perhaps.

But they have elements of a competitive market, and there's probably room for improvement in the South and West, just like there is in the organized markets.

Any other comments, or should we wrap it up?

(No response.)

CHAIRMAN KELLIHER: Okay, let me just make a brief comment. As we said in the beginning, the purpose of this conference was to review the state of wholesale power markets, and I think the state of wholesale power markets is sound, and, as I just indicated, I don't think any of the regional markets, you could characterize as being perfectly competitive, but they're effectively competitive.

They have a lot of the characteristics of competitive markets. It does vary a bit from region to region, but certainly there have been a lot of improvements, particularly in the organized markets, but there is still room for improvement.

One area is generation entry. We need to see higher levels of generation entry in both the organized markets, as well as the South and the West.

We've seen some of the facts from the organized markets, that even occur in wholesale power prices that are troubling to many, are not adequate to support significant levels of new entry.

And we also do have the overhang of uncertainty and climate change policy, but there's been a lot of progress and there's room for improvement.

I'm impressed with the commitment by the RTOs to make continued progress and make the markets more competitive, and I think we've seen a lot of successes in RTO policy.

RTOs were set up for different reasons. They were set up to improve reliability, to provide greater transparency, to improve grid access, to improve regional planning, among other purposes, and I think we've seen a lot of success, particularly in those four areas, and we've heard the facts today.

I have enjoyed the conference, and I'm glad my colleagues have been so committed to it through the day. I just want to thank everyone for participating. Thank you very much.

(Whereupon, at 4:05 p.m., the conference was concluded.)