Harvard Electricity Policy Group
Twenty-Eighth Plenary Session

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RAPPORTEUR'S SUMMARY*

Session One: Contracting Investment and Expanding Demand

In the immediate aftermath of the California energy crisis and Enron's disclosures, financial markets have turned away from electricity investments in new plants. Widespread reports of closed capital markets have produced the related phenomena of corporate restructuring to improve balance sheets and delay or cancellation of discretionary expenditures. Delay of power plant maintenance moves problems into the future. Cancellation of plant construction runs against the prevailing public policy emphasis on ensuring adequate or more than adequate capacity. All the while, demand is growing along with economic recovery. If these are the trends, then the crisis associated with high and volatile electricity prices may return sooner rather than later. What challenges does this financial picture pose for current restructuring efforts? What urgency does it lend to improving the institutional structure? What is needed to provide sufficient stability and incentive for the market to provide the investment that the regulators see as necessary?

Speaker One

Will re-regulation end merchant generation and should we care? I lay out the case for merchant generation based on experience so far and then talk about how re-regulation threatens merchant generation in a variety of ways and identify the problem that Wall Street now is the one looking to cut off or sharply reduce or increase the cost of capital for future development. Then I discuss some of the things that can get us back on course.

Merchant generation has provided 120 GW of new generation capacity over the last five years, dwarfing the amount of generation that has been built under traditional utility cost of service base. Now it is the dominant source of generating capacity. This has been a

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positive development in many ways that has not been the case in the past.

It is capital efficient in terms of capital structures; fuel efficient in terms of dual fuel, single fuel, the fuel mix, the heat rate, efficiency levels that trade off between capital and operating costs; location efficient, particularly in a context in which interconnection costs are being efficiently handled, whereas in the past, interconnection costs were just rolled into single postage stamp rate structures; risk efficient with the owner bearing the risk; tax efficient, with newly developed and low-cost, tax-preferred means of financing generation plants; and operationally efficient.

We now know that the forced outage rates in highly competitive pools have been going down over time. If you extrapolate the reduction in forced outage rates in PJM over the last five years across the country, you would pick up in the neighborhood of 20-30 GW of new capacity essentially for free.

Finally, it's environmentally efficient in the sense that you're not using eminent domain for merchant plants, and you are internalizing not only the immediate externalities, but the ones that can be reasonably anticipated in the future, because the builder now must attempt to anticipate environmental costs.

The law of supply and demand is working on the supply side. A good example is the experience in 1998-99 in the Midwest where the run-up in prices led to a rapid expansion in new capacity, which then drove down summer prices in the last few years. Another example is California, where an increase in retail rates at the beginning of 2001 over the course of the next twelve months on both a temperature- and growth-normalized basis, showed a measurable reduction in electric usage in the state.

Despite this relatively positive news and the development of markets in merchant generation, re-regulation is looming on a number of fronts. Perhaps the most disturbing thing is the withholding concept that became crystallized in FERC's November order. Withholding is when you don't sell for your incremental cost or for an undefined market price. We can trace the concept to the expectation that a generator in a central pool with a capacity requirement should be a marginal cost bidder in the real time market, and that basic expectation has morphed into the market power withholding principle now being applied to bilateral markets, pure energy markets where there's no capacity requirement, forward markets, and to wholesale trading generally, not even necessarily involving a generator.

One danger is the application of this principle to wholesale trading, when one is not necessarily talking about a generator making what we might call a first sale of electricity. A refund condition invites a buyer to potentially renege on an obligation by claiming that the seller is selling for more than its out-of-pocket or incremental costs. If you have any, you create large regulatory risks on a very narrow margin wholesale trading business. You're in danger of cutting the liquidity and the number of market participants.

The Automated Mitigation Procedure, or AMP was introduced on a temporary basis about a year ago as a market power fix to a seams problem when on June 26, 2000, prices in New York went above a thousand dollars east of the Central East constraint. I think observers of government have said that there is nothing as permanent as a temporary government solution. Now AMP is not only essentially permanent in New York, but is in danger of spreading all over the country.

The market power misdiagnosis on that hundred-million-dollar day is that it really was a seams problem because there was enormous available transmission capacity into the eastern portion of New York during the critical hours. PJM had more than 3000 MW of relatively cheap capacity into New York and New England had more than 2000 MW.

Now New York faces a potential capacity shortage in the next several years. The ISO has identified the need for more than 7000 MW by 2005, which means that new generation construction ought to start very son. The state has actually approved 4400 MW. The critical issue is how much of that is being negatively affected by factors such as re-regulation. There are reasons to believe that re-regulation is playing a not insignificant role in the cancellation and delays of even the approved projects.

The financial markets provide an illustration of how important the tops, or the highest prices, are in a cyclical commodity business. If you began with $1,000 in 1966 and invested it in the S&P index over the next 35 years, your investment rose to $1,710. That's the top line. In every calendar year, if you remove the best five of the 230-odd days that the financial markets are open, your $1,000 would have become $151. Obviously, this is not a perfect analogy to electric generation markets, but it illustrates what can happen when you take away what might be called the spikes or tops of any investment. We've now seen a resurfacing of the vintaging concept, where the idea is that we're going to treat new generation better than what was built after Order 888 and we were given the promise of market-based rates.

Those who lived through natural gas regulation know that it was the same thing that occurred with wellhead regulation: everybody will get higher prices if you drill now. It went on and on and the system became absurd as the decades unfolded. We've now seen a resurfacing of the old jargon. Commission orders talk about capacity prices being charged during a locked-in period, which in the past was sort of a rate concept. Market mitigation is being justified on the basis that we need it so we can control prices when supplies are low. If the real point is to remove all the spikes and tops in the market, the danger is that a cyclical business simply cannot be supported by the stumps.

A second-best solution to removing the tops is a capacity requirement proposal. It should be part of standard market design because a pure energy market is not possible now or in the foreseeable future. You can equate energy prices and caps and capacity prices through modeling. But if you only had an energy-only market, and you had a one-day-in-ten-years loss of load probability, your energy cap would have to be in the $12,000-30,000 per MWh range. An example from PJM based on a Hobbs calculation illustrates the kind of energy cap you'd need: today we're talking about energy caps of a thousand dollars, so we are nowhere near close.

The kind of capacity payment needed with a thousand-dollar price cap is $1,000 a megawatt year and it must be a real capacity payment, not one where the generator gets it sometimes and in some years it's zero and in others it's the cap. The average, obviously, isn't the number that you need to get.

One can argue over how much of what hasn't gone well in the investment community is related to re-regulation. Re-regulation, in a sense, says that things may never get better. The bottom line conclusion is that the next 120 GW of merchant generation is not going to be an easy sell to Wall Street.

What you want to focus on is market structure, not behavioral micro-management; respecting contracts; disavowing retroactive refunds; limiting the withholding concept to its origin; including a capacity requirement in standard market design; and explicitly recognizing that volatility has a very important role in achieving efficient generation, transmission and demand side investment going forward.

Speaker Two

We're trying to create competitive wholesale and retail electricity markets, competitive generation, marketing and retailing sectors and an effective organizational arrangement for the transmission and system operating platforms upon which competitive suppliers and competitive buyers depend. Why we are doing this also becomes a checklist to evaluate how we are doing.

The why is to provide better incentives for controlling capital and operating costs of new and existing generating capacity by making them subject to market constraints; to encourage innovation and empower supply technologies; to shift the risk of "mistakes" to suppliers and away from consumers; to reduce retail electricity prices for a sustained period of time; to provide an enhanced array of retail service products, risk management, demand management and service quality differentiation, while maintaining or enhancing system reliability and improving environmental quality.

The most successful aspect is the enormous investment in new generating capacity that has occurred, adding about 100000 MW in the US over the last three and a half years. However, many merchant generating companies face a challenging financial situation. New capital is almost impossible to raise, and a substantial amount of debt will be rolled over in the next few years. The CFO of a merchant generating company remarked recently that his cost of capital was infinite, which is another way of saying that the financing window is essentially closed to new investments. Many announced projects are being cancelled or delayed. In my experience, when companies face cash flow problems, one of the first things they do is cut maintenance expenditures. I would not be surprised to find that there has also been a substantial reduction in short-term maintenance in an effort to conserve cash.

Should we be concerned? In the short and medium term the generating supply situation looks very good. Combined with the relatively slow recovery in electricity demand growth and the recession, overall there appears to be an attractive supply-demand balance for the next couple of years. Potential shortfalls in southwestern Connecticut and New York City reflect transmission constraints, rather than a shortage of regional generating supplies. Nationally, the southwest continues to be relatively tight. If there are increased forced outage rates in California, compared to the assumptions that the California ISO is making, there could be a tight supply situation there as well if the hydroelectric supplies in the northwest are not friendly.

Longer term, can the reform program survive a boom and bust cycle of surpluses and shortages of generating capacity and the associated price volatility? I think the answer is probably no. We went from a picture in the mid-1990s when there was effectively no new generating capacity being added almost anywhere to 40000 MW of new capacity being added last year. In 2002, depending on which of the numerous uncertain databases one uses, it could be anywhere between 55000-65000 MW, although looking at the adjustments that have occurred in the past, it would more likely be 55000-60000 MW of new capacity.

A word about announcements: something like 250000 MW of generating capacity was announced prior to 2002 for completion primarily in the first half of this decade. Roughly 125000 MW of that has formally been cancelled or significantly delayed. Of course, one is under no obligation to announce project cancellations or delays and these numbers are necessarily uncertain.

NERC recently released an assessment for August 2002. Formerly it used reserve margins to assess generating capacity. Reserve margin is peak capacity minus peak demand divided by peak demand. Sometime in the 1980s, NERC decided those numbers were too big, so it began calculating capacity margins -- peak demand minus capacity over capacity. Reserve varies from region to region: in New England, traditionally, it is about 21 percent, and in California about 16 percent.

NERC's last long-term assessment found that until 2005, if the projects identified by NERC's consulting firm are completed, there will be very comfortable reserve margins at least on average, for the country in 2005. However, out to 2010, if there is not a significant increase in investment in new generating capacity or in the projects that were on the list for completion post-2004 – the most likely to be cancelled – there is a real problem if the investment cycle does not return. NERC assumes peak demand growth is about 2 percent a year and energy about 1.9 percent. This is substantially slower than 1992-2000.

The reasons for the lower demand forecasts are assumptions that GDP will not grow as quickly as it did in the last eight years of the 1990s when it was 3.7 percent per year. The typical forecasts used now are about 3.0 percent real GDP growth per year. Another reason is the gradual phasing in of the more efficient appliances when standards were changed at the end of the Clinton administration.

All forecasts are subject to uncertainty. NERC tries to make its demand forecast in the middle of a range and provides a high and a low demand forecast. We could be lucky: the economy could grow more quickly than expected. Obviously, the more quickly demand grows, the closer will be the day when additional investment is required to balance supply and demand efficiently.

The Energy Information Administration (EIA) does not base its forecasts of generating capacity additions on announcements or tracing of project completions. Its model shows that we don't need more generating capacity between now and 2005. That is not inconsistent with NERC's forecasts. However, out to 2010, there really is a need for an additional 90-150 GW of capacity to meet traditional reliability criteria.

What is interesting about the EIA forecast is that there are surprisingly few retirements. There is over 100000 MW of old oil- and gas-fired generating capacity in the US with heat rates of 10000-12000 BTU per kWh. As combined cycles enter the market, this kind of capacity should be retired over time. However, the model doesn't know what kinds of maintenance investments are being made, or how expensive it will be to retrofit them. If there were to be a significantly larger amount of retirements, the demand for new capacity would be substantially larger. EIA forecasts 1.8 percent per year growth in electricity demand.

It is not surprising that the market would react to developing surplus and low prices with delays and cancellations of projects. It was inconceivable that the market could have absorbed 250000 MW of announced generating capacity. Everybody who looked at this would apply some discount factor to how much of it would be completed. Fifty percent seems to be what people like to use. Some of this is what you expect in a market. A benefit of competition is that as supply and demand conditions change, you don't just keep building the plants because you've sunk costs in them and want to be able to put it in your rate base, but that you actually have the incentive to slow projects down. I think it is important to recognize that this isn't all regulation.

The fallout from Enron, accounting irregularities, wash trades and other things have clearly depressed the market valuations for merchant generating and trading companies and have contributed mightily to the closing of the financial window. You can't separate this from the end of the stock market bubble, the collapse of the Internet and telecom sectors, or all the criticism that investment advisers have received in the last several months. Investors are looking more carefully at the darling investments of the late 1990s, trying to understand the real economic prospects of these companies. When they look behind the bubble, they don't like what they see: uncertainties that make it difficult to place a value on new investments; uncertainties about the pace and direction of retail competition and the restructuring programs at the state level; concerns about the loss of political support for competition at the state and federal levels.

There are limited opportunities to obtain medium- and long-term commitments from LSEs for supplies for new capacity. This is partially due to the fact that retail competition has not lived up to its promise. Investors are looking for more than recovering their investments through spot market transactions and price spikes. They would like longer-term commitments made by load-serving entities to generators to help support the investments and reduce uncertainties about cash flows.

The continuing process of reforms in the wholesale power markets also creates uncertainty. Inevitably, it leads investors to discount the price forecasts for the future that support the investment proposals that are brought before them. Uncertainty about the rules governing gaming and market power behavior and associated liabilities, combined with increased regulatory and political scrutiny of wholesale market behavior are clearly having an effect on investor confidence. And having state policies that are so diverse operating on the same electric power networks does not present a picture of a nation moving towards a new vision and a new model for supporting electricity investments.

Even in states where the retail program has been reasonably successful, like Pennsylvania, retail competition for industrial customers started out like gangbusters and then moved negatively, and it looks similar for the residential sector. California saw a modest movement toward retail competition. Then the retailers returned the customers to their host utilities during the high-priced periods and then at least the industrial customers moved back as quickly as they could to avoid some of the costs that California took upon itself in spring 2001.

This back and forth among retail, native and utility under default service rates is not very conducive for investment planning or for LSEs to enter into long-term arrangements, since they never know where the customers are going to be, or the effects of the interaction between market price signals and default service obligations in prices.

The states need to clarify and stabilize the retail procurement framework so that load-serving entities have a picture at least five years out, and have incentives to contract forward to meet their obligations. Many states that adopted retail competition are nearing the end of their transition periods, when reform programs expected most customers to have moved to retailers. Many customers are still with the host utilities, paralyzing the ability of buyers and sellers to enter into longer-term arrangements. States that have not chosen to adopt retail competition ought to make clear whether they're going to do it, at least with a five-year period that would let traditional load-serving entities know if they should plan on having an obligation to serve.

FERC needs to push quickly with a standard wholesale market design and the RTO initiatives. I believe the capacity obligation should be part of the market design. It's inevitable during this period that we are going to have must-offer requirements and that in an effort to mitigate market power we're going to end up clipping high prices in some cases to attract new investment.

It is also necessary to harmonize regional planning, to avoid free riding and to compensate generators for other imperfections that may be associated with the mitigation methods that are being put in.

Market participants need to support reasonable rules to clean the house of bad actors. If you don't like the way FERC diagnoses and mitigates market power, you've got to say, "Here's something that is better." That is the way you make progress. I think FERC does need to define clearly what behavior is permitted in these markets. Now we're rolling the dice. We don't know ex ante what is legal and illegal. It's not fair to subject suppliers to potential damages if they don't know the rules of the game.

This will discourage investment, especially with vague, open-ended refund liabilities; I think all refunds are retroactive. As a metaphor, you can't run a competitive electricity market under a scheme where you take 60 days to suspend market-based pricing authority and then three years to decide the refund obligation. The model here should be one with clear rules. If there's a problem – and I think this is a quid pro quo that market participants need to recognize – the market monitors need to act quickly, and damages should be reserved as a last resort to respond to egregious violations of market rules.

I think the metaphor should be damages from the antitrust context. Use Section One of the Sherman Act, where there is a per se rule against price fixing and if you are caught you pay damages. If there are other suppliers in the market who have not been engaged in the price-fixing conspiracy, they don't pay damages, but you pay their damages if you are caught.

FERC needs the resources and ability to interact on a continuing basis with market monitors. We can try to do things prospectively rather than retrospectively and make a serious effort to increase market transparency.

Recognizing that there has been an enormous loss of credibility of the deregulation program, and especially of electricity retailers and marketers over the last six months, regulatory reform and competition programs will not proceed very quickly unless confidence can be restored on the part of individuals and their representatives in state and federal legislatures. Market participants need to assure their shareholders and the public that they are not just creating a big casino. There really are very important social benefits that will accrue to consumers in the long run.

Speaker Three

I am from California. My concern is a replication of 2000-2001 in 2004-2005. The state had a significant underlying supply and demand imbalance and a flawed market design that was overly complicated and based largely on a spot market. The average age of the power plants in 2000 was over 37 years old. From 1990-1999, the state grew by 11 percent with respect to demand and lost 2 percent in terms of generation capability.

California normally relies on about 15-20 percent of its demand being met from imports, primarily from the Pacific Northwest. That was reduced by half in 2000. As hydroelectricity is depleted or not available, natural gas becomes the marginal fuel. At that same time, natural gas costs increased throughout the US, with specific ramifications in California, due to an explosion on the El Paso pipeline and some other gas-related issues.

The analogy of the perfect storm has been used to characterize what happened in California: the convergence of a number of adverse supply and demand conditions, any one of which would have had significant impacts on the state and its neighbors. Why didn't everyone see this coming? There was a serious case of groupthink in the state. Everybody looked at the huge surplus of power in the west and I think honestly believed that it last forever.

The aging fossil fleet ran 60 percent more on average in 2000 than 1999. Some of the 45-years-plus plants ran over 108 percent. These old units have very high heat rates and operate under strict air quality regimes. A lot of the increase in outages in the winter of 2000-2001 had to do with deferral of SCR or quality control equipment, as well as the fact that we were basically exhausted.

California's utilities were also severely limited in forward procurement. The groupthink position was that you always went short. As a result, units were sold without any buy-back revisions, unencumbered. The old plants went and the utilities had no obligation or opportunity at that time to buy back power.

There were reliability must-run contracts originally with a number of generators. We spent a great deal of time in 1998-1999 relieving a significant number of these RMR contracts. The freed up generators were no longer obligated to provide resources under those contracts. Probably the most significant issue is that the state's investor-owned utilities were effectively precluded from entering into longer-term contracts, largely due to the absence of basic prudency and procurement guidelines going forward.

The president of California's Public Utilities Commission now says it gave the IOUs plenty of opportunities to go forward. The fact is it did not, because the IOUs bore a significant amount of risk without any sort of prudency guidelines. What is unconscionable is that two years after the crisis first emerged, California's utilities still have no prospective prudency guidelines.

Utilities were required to buy and sell only through the Power Exchange. These power purchases were reasonable. In San Diego, where the crisis first emerged in the early summer of 2000, purchases through the PX were reasonable at $250-300 per MW. But if they entered into a long-term contract, say five years with a generator for $50, they were exposed to some longer-term reasonableness risk, which is clearly a perverse incentive.

The ISO's real time market was designed to handle 3-5 percent of the load. But because there was a price gap in the real time market, utilities were under-scheduling in the day-ahead markets and showing up in real time. This was perfectly rational economic behavior because there was a cap in the real time markets and none in the wholesale markets. With everybody showing up in real time it produced an over-reliance on short-term markets.

Unlike other places, California basically had wholesale rates that fluctuated with the market. The retail rate freeze in place meant that the end-use customers did not see the run-up in terms of energy costs. That caused significant dislocation and resulted in the insolvency of the utilities.

The problem was that a lot of the market expectations were hard-wired into the legislation, known as AB 1890. There was a guaranteed rate decrease for customers. Utilities had an opportunity to recover their stranded costs. Basically, everybody got what they wanted. As the world changed, California could not. And the PUC was a little slow to address some of the rate issues in 2000.

California's relationship with the federal government is also important. From 1997-1998 we told Washington, "We have a little different way of doing things. Leave us alone." I believe all fifty-four members of our Congressional delegation signed a letter saying, "Leave us alone." The concept that somehow, the federal government hasn't been paying attention to the state or turned a blind eye just isn't the case. The bottom line is that politics and physics do not mix. California is highly dependent upon its interrelationship with its neighbors, but sometimes it wants to be an island. California's market structures obviously have regional implications.

Is this history relevant? Today, we're seeing economic recovery in California happen at a quicker pace than perhaps nationally. However, that also means that a corresponding demand is beginning to come up. An El Nino is coming which means historically, less snow pack in the Pacific Northwest. Up to 2000 MW of in-state generation is at risk due to air quality issues. Due to current market conditions, the owners of those plants are saying, "Leave them off because we don't want to put the money into air quality control equipment if it's not going to pay itself off." We've got stalled infrastructure investments and other impacts from the Enron fallout, with people basically trying to shore up their balance sheets. There is regulatory uncertainty and a lack of meaningful market reform, at least at present.

Path 15 is the transmission bottleneck between northern and southern California that also affects transfers into the southwest. Under California law, the PUC has siting authority over transmission lines. I think the concern has been that since it doesn't necessarily control this, the PUC doesn't really want to see it go forward. It's a cost effect, which in the old days under a bundled transmission tariff obviously is a reasonable thing for a PUC to be concerned with, but in this set of circumstances, it really isn't relevant.

All these things seem to be lining up in a way that could be adverse. We need to be thinking in a way that makes sense from a regional basis. Market reform is underway, not without a fair amount of discussion, but we are making some progress. The question is whether the types of reform that we need will be workable in the 2003-2005 time frame.

Question: If buyers under-scheduled in the day-ahead market with the hopes that the real time prices might be lower, did the pattern of under-scheduling, if it did occur, result in the real time prices suddenly getting higher and lead to self-correction?

Response: Real time prices were capped in the ISO at $250, so buyers basically limited their exposure by showing up in the real time market. This did not happen secretly. There were long discussions in very open ISO meetings. It was a function, I think, of a flawed market design.

Speaker Four

About a year ago, the New York ISO issued a report that made a dire call for new generation. Something on the neighborhood of 8600 MW needs to be built and operational by 2005. Now an update to the report calls for 7100 MW by 2005. To get that we had called for about 3000 MW that would need to be approved and get going this spring. About 1500 MW have been approved, but 750 MW of that has been put on hold indefinitely. This generation is sorely needed, as evidenced by August 2001.

Our planners have talked with the neighboring ISOs. New England has seen 45 percent of its planned capacity withdrawn from the markets. In PJM, over 45 percent of its capacity has recently been withdrawn. The question is why. For both, the likely answer is supply and demand. Both have had some success at getting new generation built, but that is not the case in New York. There are several possible reasons. One is the reduction in price. The average price for 2000 was $57.90 per MW hour, versus $51.42 in 2001. I'm not sure how much of this price reduction directly translates for the generators into their concern that they have less opportunity to get a return on their investment. Another plausible reason is the capital investment market. The price volatility and lack of long-term guarantees certainly play into that, but also the scrutiny of accounting practices.

How do we do fix this? Possible ideas are to get longer-term contracts in place for the load-serving entities with both capacity and energy. That will make investors more comfortable with providing capital for new generation. But that's not where the LSEs are going. Although some would like to lock in some portion of their demand over the next few years, I don't think any of the LSEs say they want to lock it all in. They see prices that are declining and they also want to take advantage of the open market. Another possibility is to let shortages take effect and prices skyrocket. That's the supply and demand piece. High prices on the peak days are necessary for some generators to cover their fixed costs, particularly when you're talking about peaking units that don't run for many days over the year. One idea is that perhaps the regulatory arena needs to be revised to provide some support for requiring some of the LSEs to better hedge their positions going forward. If pass-throughs were removed, that would give them a certain incentive for hedging loads and keeping prices low.

In summary, New York needs generation. It is making progress through its Article 10 siting process, but there have been significant withdrawals from the market. Unless this trend reverses, the state will miss out on the reliability, cost and environmental benefits associated with new generation investments in New York.

Question: What effect might the proposed merchant transmission going into New York have on new generation projects?

Response: I think it is positive to have the merchant transmission coming into the Long Island area. Is it enough? No.

Question: Is it chilling the generation inside New York?

Response: It's a very small capacity that's being added and I do not see it as any more chilling than, for instance, another generation plant that had been started in the New York City-Long Island area.

Discussion

Question: What information and requirements are needed for access of information? What should the response time be and how much information should be made public? My experience was that there was information that the marketers were sharing among themselves because it was necessary in order to operate the system, but at the same time, they were telling regulators that it was competitive and proprietary information.

Response: In the late 1990s public officials went too far in suppressing the availability of information to the public about the behavior of buyers and sellers, bidding information, price information, availability information of generating units and other information. Over the past couple of years, a number of ISOs have begun to release more information with some lag so that it couldn't be used to facilitate cooperation. During the transition to a well-functioning set of wholesale and retail markets, the primary burden should be on those who don't want information released to indicate why it should not be, either because it is commercially sensitive or because it reflects the FTC's concerns about releasing information too quickly or in too disaggregated a form because it would facilitate collusion. I like to look at England and Wales because I think the system there has worked quite well. You can get all the information you want, at least during the days of the pool when they were refining it. You can get bidding data by company; price information; almost everything with some lag. We ought to have that kind of public disclosure here as well. People say that in deregulated markets marketers do not have to provide this information. But we are not yet legally fully deregulated. Even the airline industry still conducts a 10 percent ticket survey. You can get that data from the Department of Transportation whose analysts use it all the time to assess market behavior. It is important that this information be provided unless there is some good reason not to.

Response: We do not object to disclosure to market monitors that are operating within the scope of their market monitoring authority. FERC has come out with a new quarterly reporting requirement that calls for more information to be disclosed publicly and that will take effect later in 2002. I do not have any philosophical objection to public disclosure, other than I think that it is a double-edged sword. Now competitors can exchange information essentially through a public disclosure requirement about pricing and cost data and bidding strategies, which might not otherwise occur. I think there is a balancing that people interested in competitive markets need to think about.

Response: Having had to deal with this issue at the California ISO, we actually put information out with a lag period. It was very controversial because there was a compelling argument that markets work better if they are more transparent. Getting more information out there sooner is a good thing. Ironically, some people are now trying to make it a crime to release reliability-related information. I think having the information out there is a positive thing with transparency, but there needs to be a coming together about precisely what information and about the unintended consequences of having it with or without a time lag.

Response: A lot of the information is available to market participants. The question is whether it should be made available to the public. I have graduate students who do research. They try to evaluate the performance of these markets. I think it is socially valuable work. I think it is important to give the public access to the information. People should not think it's going to lead to false accusations. It may clear the air where there is a lot of suspicion because the information is not made available. I think it is important for market participants and policy makers to come up with a protocol for information release that does not facilitate collusion and that provides the information that people in the business and watching the business can use to understand what is going on.

Question: What is the definition of lag time?

Response: In New York, it's six months, generally.

Question: Why is six months better than a week?

Response: First you have to distinguish between the information the market monitors have from what is made available publicly. Market monitors should have information in real time that is held confidential and is used in ongoing analysis. It should be available to FERC so it can react quickly. What the lags are depends on the kinds of information that you are looking at and whether you think its public release will undermine the performance of the markets. Those are the criteria. You want the information released to provide a transparent look at the behavior and performance in the market but not adversely affect market behavior. For example, you don't want to release bid curves in real time to the public because people will use them to adjust their bidding strategies. But if you release the data 60 or 90 days later – these are somewhat arbitrary – it is old news by the time the 90 days have passed. You have to look at different kinds of information in a different way. California daily posts on its Web site the availability of different generating units, basically in real time. I'm not sure that's so smart. You may want to wait a few weeks at least to make that information available.

Response: First, who needs the information? There are different ways to provide it and probably different standards that apply under state or federal law. Who has to provide it is more complicated because you are looking at information in some cases from traditional regulated entities, unregulated generators and often information that will have a trade secret element, particularly for large customers. Different lags may be appropriate for different purposes. I think there is a time dimension as well in the kinds of information that might or might not be appropriate. Information disclosure is probably more important in an immature market. From a regulator's point of view in terms of public confidence, that is arguably as big a question as the ability to have access to information in order to do a job on behalf of the public. Regulators may be perceived as being irresponsible or ineffective if the information they are using is not disclosed. Ultimately, there are probably questions of property rights, specifically trade secret law, and probably disclosure and FOIA issues that come into play, as well as constitutional issues under state constitutions.

Comment: We are changing the vocabulary from capacity obligations to resource adequacy requirements. We want to put the demand side of the market on an equal footing with the supply side. We would like to get the demand side to tell us what it is willing to pay because the only information we have comes from the supply side. We want to mitigate market power, not prices. But when the prices get high, we want to be able to explain that they're the result of scarcity and not market power, which I think is very important if you want to let volatility happen. When you go beyond the platitudes of market structure, it becomes very difficult because market structure includes conditions like hydro, snow pack, heat, cold, unexpected weather. All are important when you do structural analysis and most people leave them out. Most structural models do something like average weather, average snow pack and average nuclear plant outages. Some of us know that it is very difficult to do this type of analysis in any meaningful way. If you want to get rid of the refund responsibility, get it out of the law. I think three years for refund obligations is optimistic. I think you should think in terms of ten. A lot of information scarcity is being rationalized as September issues or national security.

Response: In 1999-2000 with the California ISO we went out for auction on demand response and did not get a lot of activity because we were focused on price caps at the time. Industrial loads started showing up at $1,600. When they went higher, you saw some response, but not a lot that was within the price cap. We need to focus on market power issues because as I see it, there are three levels: what we mean by it, how to measure market power when someone is abusing it and what the sanctions are. I do not think there is one definition that everyone has agreed on, or a common understanding of what it means to abuse market power. You may have it, but you may not be abusing it. What does that mean? As for defining sanctions, now it's like driving down the street and at the end of the day someone says, "You broke the speed limit, here's your ticket and we'll tell you how much that ticket is going to cost you ten years from now."

Response: Markets for non-storable commodities do not work well when you get up against capacity constraints if there is no demand elasticity. You need supply and demand. The equilibrium price is infinite. Until we can get demand elasticity into the market, energy-only markets are never going to perform satisfactorily when supplies get tight. The dilemma is when you start to then use administered mechanisms to mitigate or cap the prices. Inevitably, you will capture some price spikes that you need to clear the market and some that would be indicative of market power. I think efforts have been made to create an active demand side where customers are signaling their willingness to pay. Their willingness to reduce their consumption as prices rise is fundamental for making these wholesale markets work. Until we can do that, it is inevitable that we have to look for second-best mechanisms.

Comment: $1,600 is a decent bid.

Response: Particularly when there were widespread blackouts, there was a lot of interruptible load. Workers showing up at the Boeing plant halfway through a shift were being told to stand around and do nothing. There was a great deal of willingness on the part of some very large industrials to do quite a bit during the crisis. But the important demand piece is still lacking insufficient mechanisms to address the issue.

Comment: If you gave Boeing the same opportunity to bid into the markets that the generators had, it could say that it wanted to either run the whole shift or no shift at all, which is closely equivalent to what generators are allowed to do in the eastern markets. They don't have to turn the stuff off in the middle of the shift and they can decide whether or not they want to have it.

Response: The New York ISO is engaged in what might be called the micromanagement of units, evaluating and making sure that they do things in a certain way. I think this is a dangerous proposition because it leads inherently to the generation capacity shortage we're seeing in New York. Ten years is certainly a disturbing period to wait until you know for sure what your revenues and earnings were. We can disagree about what the Federal Power Act requires in terms of refunds; I assume eventually the DC Circuit Court will end up resolving that.

Response: New York continues to make changes and improvements to the market mitigation that we find to be necessary. One of those is stepping back and looking at units as a group. We haven't had investment in generation for many years. While market mitigation may be a part of what's making generators less likely to jump into New York, it is not the only, or primary, reason.

Question: To what extent should states encourage – through what's left of their integrated resource planning processes –

utilities and other LSEs to engage in bilateral contracts that essentially reduce the risk of volatility, buying longer than they might have otherwise? If regulators encourage utilities to use the bilateral markets to reduce this risk, have we gained any efficiencies?

Response: What we saw when people were very bullish about restructuring is an enormous amount of private capital coming in to build power facilities -- probably the highest-risk kinds of investments you can make in the power industry. I believe that the bilateral market is extremely important. The mistake in California was having a huge percentage of load showing up in basically a day ahead or real time market. If you only had 10 percent fluctuating in those markets, the energy spikes in the western markets would not have had the impacts they did. It is important for states to create procurement guidelines for the utilities. They would be prospective in terms of a presumption of reasonableness. Many states have renewable requirements that can be done prospectively.

Response: You can't answer the question properly without defining the retail procurement framework. You need a set of compatible institutions with regard to the obligations of the LSE, what opportunities there are for customers to shift back and forth and how the LSEs can best meet their obligations. For example, if you are in a state where customers can leave and come back at a moment's notice without penalty, it seems to be unreasonable to impose upon an LSE an obligation to enter into long-term contracts, because you will find yourself in a situation where they contract now, you pass it into retail rates, the wholesale market prices decline and the customers want to leave and people them scream about stranded costs. States need to think harder about what they really want to do on the retail competition procurement front, and to have a program that is compatible with the LSEs' obligations. This is easiest in states that have decided so far not to have retail competition, although the threat is out there and, I think, deters long-term contractual commitments because companies do not want to create more stranded costs. In states that have retail competition programs that are moving along, there will be a cliff that they fall over unless they confront the fact that if it is not working as anticipated, soon everybody will be in the spot market. If you think you need a long-term safety net and you really don't believe in competition, you probably should not have it. This is not a question of a return to cost of service regulation. LSEs purchase portfolios of contractual arrangements in the competitive market that may range from a week to seven years. They are not individually building power plants. They're going for the best deals they can get. I think that kind of wholesale competition framework can work very effectively even in a regime where there is no retail competition, and can help to provide benefits to consumers over the long run.

Question: Is a capacity obligation or capacity requirement driven largely only by the inherent inefficiencies in such an obligation that creates and in part goes to the relationship with the retail programs in place, or is it also or in part related to flaws in the existing capacity markets? In the California ISO's recently proposed market competitiveness index, is it useful to establish exeunt rules and does it establish a self-disciplinary action in the market among participants?

Response: What conditions are needed for an energy-only market to work efficiently? One is that you have an active demand side where ideally, all consumers can place their willingness to pay into the market and can react instantly to changes in supply and demand. We do not have that. Another is free riding, where you have entities operating on the same network that can essentially lean on capacity that has been built and dedicated to others. When there are shortages now, we don't say, "You didn't have a contract so we're going to cut you off and keep the other guys on." We cut everybody off randomly. Until you can match the costs of curtailment with the contractual obligations, you potentially have a free rider problem. There are also other criteria. In an ideal world, you would do everything with instantaneous real time prices on the margin with everybody in that market. I also think we have to distinguish between a capacity obligation and the functioning of capacity markets. Obviously, a capacity obligation is not going to be effective if the capacity markets are not themselves reasonably competitive. With PJM for example, there has been some concern about the performance of the capacity market and allegations about market power being exercised. I think that is a separate issue from whether it is desirable to have a capacity obligation.

Response: Theoretically, an energy plus capacity system doesn't necessarily produce more generator revenue, for example, than a pure energy system. It simply is a redistribution, in effect a smoothing of revenue streams generally over time. I think there is inefficiency that gets introduced by capacity. There are different ways to look at inefficiency. One concern is how to push down to the retail customer level instead of only having energy you had to figure out how to push to the meter. I think this increases the difficulty in getting an efficient response. The market power issue on capacity in PJM during the first quarter of 2001 is an interesting question. Was it really market power or should it be defined as market power?

Question: Some of the things that Enron did were wrong and some were not. It is not clear to me that the political system will allow federal regulators to make distinctions like this and the recommendations we are discussing may be too difficult for them to do and to follow. What is your sense of the political climate?

Response: "If Enron did it, it's bad" is not necessarily a terrible rule of thumb to use. There is pressure on FERC to rein in what is perceived as a bunch of cowboys who are turning electricity and gas markets into gambling and casinos. A challenge for FERC is to manage that process and respond to legislators' concerns in a way that doesn't involve the use of blunt instruments. Historically, when there have been adverse events that have led to new regulations, political pressure does lead to some bad regulation. We have to explain to the people who really are trying to listen what is happening and how to fix it. There is no question that there is a danger of over-regulation.

Comment: There is a need for people who have a rational, longer-term view not to respond to political hysteria and to help legislators understand the unintended consequences of trying to crank down too tightly on markets that are actually solving problems. If there are things in the Enron memos that may be illegal, people should be held accountable. Undoubtedly, while a lot may not be illegal, it is the kind of behavior one doesn't want to see in a workable competitive market. There is also a lot that is exactly how markets work.

Question: The pending New York-New England merger potentially might help solve New York's problem. A recent cost benefit study shows that the benefits for that merger would accrue largely to New York and the cost to New England would be fairly significant. Should benefits from such market mergers be spread across regions to encourage the equitable spreading of generation? If there were to be some sharing, would it help or harm new investment?

Response: As a practical matter, when you are trying to make a voluntary deal, there has to be something in it for everyone. I do not see how New England solves New York's problems without substantial investments in transmission capacity because there is a very skinny interchange between them. I can't imagine it will have such an enormous effect on New York's access to generation. I think there are benefits to both sides by eliminating the seams problems. Those are probably larger benefits than the additional access to generation New York might get.

Response: It is important to keep the impacts as neutral as possible when addressing RTO issues generally, without picking winners or losers. In the final analysis, it is an integrated system and you have to think about winning or losing over a time frame in terms of how the benefits accrue.

Response: Path 15 in California obviously leads to regional debate. Californians might say, "Why should we send $100 million north to Idaho to improve a substation when we may not be able to get direct benefits?" and in Idaho they might say, "Why should we spend money to affect transfer capabilities down in California?" There is no easy answer, but we need to think about things from basic interstate infrastructure, not from localized, "If it's good for my neighbor, it's not good for me" thinking.

Response: There are some physical problems between New England and New York and we need generation or transmission to solve them. In the short term, the benefits accrue entirely to New York; in the longer term, the cost benefit study showed that both sides will eventually receive benefits from the market merger.

Question: We have had no new nuclear for years, no large hydro, hardly any coal. Almost everything is gas because it has good heat rates, reasonable capital costs and much shorter construction periods. The latter point especially supports a construction strategy where the supply increments are more closely matched to the increments with demand growth. But if the emphasis on new construction remains focused on gas for an extended period, the downside is that the portfolio balance might shift. Given that the capital needed to finance generation probably tracks well with the revenue stream that is going to come from that generation, which tracks well with trying to bring in increments that closely match demand growth, from the market's perspective, what will assure or attract financing for some of the longer lead-time baseload generation?

Response: Even though the 120 GW added in the last five years have been predominantly natural gas, the largest source of electric generation is still coal. We have been accomplishing a diversification away from coal. We are really getting the advantages of natural gas as a fuel for electric generation, and I think for improving the nation's portfolio. I do not see a lot of downside with that move in the foreseeable future.

Response: We are not seeing investment in new nuclear power plants because they are not economical. Even with fairly optimistic forecasts, it is $2,500 per kW by the time a plant is completed and it cannot compete with gas or coal at that price. Coal is different. The cheap coal happens to be in parts of the country where it's also easier to build plants. If we are trying to get more long-term contracts into this business, where coal is economical, it could come into the system. The construction lead times are not that long. There are uncertainties about future environmental restrictions, but people will have to make that business decision. Right now, the US is 52 percent coal, 20 percent nuclear, about 8 percent hydro and the rest is gas and a tiny bit of oil. I do not think that is a bad mix of generating capacity.

Response: If there is a concern about a run-up in gas prices, are there mechanisms that give LSEs some guidance about what they can or cannot do with respect to mixing up their portfolios? This is important at the state level. You have generation built in different states to serve other markets -- a lot of it seasonal exchanges and highly controversial. You need to address this on a state level.

Question: Regarding the cliff that many states are approaching in terms of their retail markets, I see a distinction drawn between what states need to do about residential customers and the commercial and industrial customers who have in many cases benefited from having some sort of retail competition, though imperfect. Assuming we move to the next level of retail competition where customers do see variable pricing and LSEs and non-utility LSEs sign up customers, what is the generator's perspective? What do we mean by longer term and should the counterparty be an incumbent utility that has rates of return and can sign those types of agreements?

Response: Creditworthiness is always an issue, but not an unsurmountable one. Most generators like to sell out portions of their plant output. Often, there is portfolio management from a generation perspective as well as spreading that over different time periods and different customers. In an area where there is excess generation, I would be surprised if there would be any problem entering into a contract that could be as short as a month or as long as seven years. An operator wants to cover its fixed costs; often it uses contracts, particularly when building a new plant. The contract is like the anchor tenant when building a new shopping mall.

Comment: This assumes we are having central station power and transmission. In other countries, like the Netherlands, an influx of decentralized generation solves problems like transmission constraints and increases efficiencies. Thinking about very large-scale decentralized generation is a different picture.

Session Two. Standard Market Design: What Role Will the States Play?

While FERC has proposed a standard market design, full implementation of it requires action by state regulators. What initiatives, if any, are the states undertaking? What incentives are being provided to stimulate investment in new generation and/or transmission? What use, if any, is being made of rate base treatment of new plant? Is there a continuing place for generation and/or transmission in retail rate base? How are retail markets being implemented? Are tariff structures being revisited to comport with the prospect of standard market design? Will end users receive better price signals? How will retail tariffs impact the potential for demand side bidding? What steps are being taken to promote demand side bidding? How are siting issues being addressed? How parochial or how regional will states be in their siting perspectives? What role will state regulators have in RTOs? How are states reacting to the recent decision of the US Supreme Court in New York et al. vs. FERC?

Speaker One

Having a standard market is good, but nowhere near as important as having a good market design. I mean this quite literally in a dollars and sense mode. The cost benefit studies that have been done are full of uncertainties, but I think they show clearly that the standardization of market rules that get rid of all of the seams issues could at best achieve a 2 percent reduction in the cost of delivered power. That would benefit consumers only if the assumptions that are moderately optimistic occur to make it happen and if there is an adequate balance of market power to ensure that the sellers have an incentive to share shavings with the buyers.

More important than standardization is putting quality rules into place that incorporate these important elements: bringing a demand response into the market; getting a serious demand response that allows the people who are buying to make decisions before cost commitments are locked in; getting some degree of locational marginal pricing (LMP) that gives a proper signal about where new investments should be made; establishing a coherent set of incentives for the people who will manage the markets and evaluate how well they work.

SMD will not occur without a meaningful degree of involvement from state utility commissions. At some level states will be setting the retail rates necessary for a functioning market. LMP needs data and information that the states have. Wholesale markets that rely upon independent transmission companies that lack the mixed motives of giving preference to the generation from which they make money usually mean divestiture or holding company types of transfers. The asset transfers needed to make that happen are subject to state regulatory control. New resources will need siting that may involve a necessary condemnation power and threat or use of eminent domain. Eminent domain is only justified by a general public good standard administered by a state's utilities commission or siting council. FERC has relied on the notion of a set of independent, regional transmission organizations with two primary functions. One is what transmission companies have always done: to manage the grid, saying what gets turned off and on as we run up and down the scale of desirable dispatch from generation. The other function is to manage the wholesale market, where FERC has a statutory responsibility to ensure just and reasonable rates, based on a century of doing that through cost-based ratemaking and today, through a policy shift to market-based ratemaking.

I do not accept the assumption that markets, as a theological matter, will automatically produce the right results. They have to be markets that work. FERC's management of markets is a public fact. However, its fiduciary duty is not to say, "Let's have short-term low prices," but rather to focus on system reliability, operational efficiency and promoting efficiently functioning markets. My definition of an efficiently functioning market contains two elements: relatively low transaction costs and a reasonable recognition of the opportunity for buyers and sellers to make rational decisions about their fate and their choices. We don't want a situation in which there are really low transaction costs, but the markets are dominated by people with an interest in high prices and high throughput. While that is satisfying for somebody selling into the market, it is not for somebody who buys out of it, or for the general public good. When we look at something that is supposed to make the markets more efficient, we have to ask whether it is only reducing transaction costs or does it move us to a world where there is also an economic incentive to share the benefits.

The governance structure of the people who make these decisions is vital. It is no more logical for market participants to control the people who manage the market than it is for market participants to select the members of FERC. This function ought to be performed independently of the people being regulated. There must be a stable budget that is insulated from the influences that try to control the merit of the people affected by the decisions.

There are two models for infrastructure investment. One is characterized by a high probability of moderate returns; serious barriers to competition; and strict enforcement of traditional accounting standards. This is the model that was created at the SEC in the 1930s. It has a track record of getting many good things accomplished, despite its problems. The other model has been emerging in the last five years. It is characterized by a moderate probability of getting a high return if you do something above and beyond what's traditionally been done with the transmission grid; easy entry; and until very recently, little emphasis on accounting safeguards.

Which model are people most likely to invest in? We actually have a lot of data going back to 1995, when the issuance of the first open orders for California saw a drop in the market value of the California utilities of as much as 40 percent within a month. In the last six months we have seen the flight from capital investment.

Maybe the flight is caused by fear of re-regulation or the realization that we do not need that much investment to meet expected demand. Maybe it is the belief that we cannot trust accounting in which case, at a worldwide level, we should be happy that capital is being diverted to more reliable accounting systems. Maybe it is the fear of market volatility and that investors would prefer a higher probability of a lower return. Maybe the capital flight is really only the deflation of a balloon in which a lot of projects were puffed up. Maybe telecom and utilities are natural monopolies and there is market power, whether legitimate or abused, that means that you do not want to invest in the losers and you can't figure out who the winner is because there is not enough transparency so you do not invest in either of them.

Empirically, there is a demonstrated record of serious concern about the path we have been on for the last five years and there is a demonstrated track record of capital investment for the prior fifty years. In other words, the data says capital flights occurred in the last five years, and didn't happen in the half century before.

There are two models of how we treat the transmission grid. One assumes that transmission doesn't cost all that much; it's really useful, so let's build it. Because it is difficult to decide who should pay for what portion, it is not worth the analytical effort. This model has some serious costs, such as building infrastructure that may never be used and then we either pin the cost on a merchant plant and deter a future investment, or through a socialized cost to people who should not have to pay for it, but are doing so for the long-term good of everyone. We distort future resource allocation. If we have a meaningful choice between an efficiency investment, a generation station or a grid, and one is spread over a really wide area and the other is going to be paid for by whoever builds it, we do not have a level playing field. If you socialize, you could wind up picking the more expensive choice and shoveling the costs back and forth among the region instead of getting a good price signal to pick the least expensive choice.

If there will be a tradeoff between some things that you socialize and some that you do on a cost-causing basis, you probably ought to have a principle for deciding which things fall into which basket. The Regulatory Assistance Project would say that you only socialize something if it really has widespread benefits for everyone and that it should be the least-cost alternative. Unfortunately, we tend to pick the quickest alternative because we don't do the analysis until we need quick results. I take as a premise that the definition of least cost includes the option that if there is a meaningful efficiency or distributed generation alternative, it is looked at to see whether it indeed should be the solution.

Pricing should signal an incentive to look at all the solutions to congestion. You want a revenue stream set up for problem solvers. Whether through an RFP or a selection and criteria process, it should be reflected in SMD. I believe that the traditional cost plus rate of return regulation is mediocre. Instead, we should consider standardizing so it's easier to understand; performance-based regulation; and things that focus on eliminating congestion rather than on the degree of capital investment. Reducing congestion is the goal and the payments ought to be associated with that.

Should an RTO do resource planning? Often you need approvals from a state's public utilities commissioners because you have a siting or condemnation decision. They want to know whether a proposal is a really good idea. They are looking for expertise other than from a group of transmission owners who say that more transmission is needed. Regulators must be able to demonstrate that they took an even-handed, across-the-board look at the options, concluding that transmission or generation was or was not needed. If the project is to be paid for through socialized costs, somebody must decide what is eligible. If the group that decides who is eligible to have its costs put into a mandatory wires charge is the same group that will be paid out of the mandatory charge, there isn't much legitimacy. Finally, is this body a provider of last resort for essential regional infrastructure needs? Is it responsible for making the investment, doing an RFP and promising to pay out of an uplift charge?

I am troubled by the idea that who decides whether new generation or transmission is needed also manages the procurement process. One answer is to hope the market will solve the problem; that someone will build a plant or a line right where it's needed. We are struggling with the problem that some things can get done faster or slower which isn't always the same as what gets done cheaply or expensively. If we impose the solution that economic upgrades have to be borne by whoever is going to pay for them, the reliability upgrades are then spread around. However, creating an incentive to let the reliability upgrades dominate so that what would have been a rational economic upgrade is left hanging until it turns into a reliability crisis because then you can spread the costs around is not a healthy pattern. Another issue is that if people only put money in when they are sure they're going to get it out, that sounds like traditional cost of service regulation. If we want people to invest when they're not sure they'll get their money out, we need a mechanism that says, "There will be high returns *some* of the time."

SMD relies heavily on market monitoring. While monitoring is vital, in and of itself it is not enough. Making markets work does require some enforcers. To understand that task, you need to understand that there are hundreds of bids, each with dozens of sub-bids coming in every hour. Are they valid? You can't look at one bid at a time, but have to create a good set of incentives and rely on enforcement, rather than hoping that enforcement will catch everything. That is a recipe for a lot of litigation.

The recent Supreme Court decision, New York et al. versus FERC, means that FERC can control transmission – whatever that means – and can probably define it to include a lot of things. FERC can control sales on the wholesale side, presumably meaning that it can control anything that is sold and anticipated to be resold, but not at the retail level. The court did not address whether the control of transmission down to a very low level means that in effect you control the retail sale. FERC has a multi-part test that has worked out fairly well, but it is not how the court read the outer bounds of where FERC could go. If FERC moves to something new and different, it might well have a statutory basis approved by the court, but it would have a difficult pragmatic issue of coming up with a boundary that is definable.

FERC does not have enough employees to do the job if it really decides to get into retail. For example, it cannot answer the daily consumer complaints in New York, much less for all of the United States. It can't monitor the markets even though I think monitoring is a federal function that is being delegated to regional groups. At some point, FERC will have to work productively with others and that includes the states.

Even in states with no retail choice, there is a serious opportunity for rate design that deals with interruptible rates, and setting a consistent and predictable pattern and a price trigger where the interruptible rate level is linked to the wholesale rate level. In my state, the goal is to have a retail rate design that reflects the costs of the LSEs, including the half to two-thirds that come out of the wholesale market.

I think every state should review its fundamental rate design, whether or not it is set up for standard offer. Wholesale markets have changed radically and if you want to send a meaningful price signal, you need to have a link between them. This can be difficult because people want retail rates that are stable and easy to understand and that they can predict without paying a lot of attention. Ultimately we need what I call a unified field theory: the link between consumers' preferences and an opportunity to adjust their demands based on the price signal and most important, an opportunity to see the price signal before making an irrevocable commitment that will be collected through stranded costs or uplift. I think we get strong wholesale markets that do really good things, regardless of whether there is retail choice. If we can't, then wholesale markets are going to be flawed to a degree that says they aren't achieving what they should, and we may need to abandon our efforts within a decade. We have an obligation as a matter of intellectual and moral openness, to respect the possibility that when we take this complex equation where some of the variables are unknown, we may not get the answer that we all want. But given the problems of the old system, the potentials of the new system are good if we can turn it into a reality.

Question: Do we need a more holistic approach to siting and the like? If so, do you have an unbundled world where RTOs do transmission, but you rely on merchant generators for generation? How does that really work?

Response: The RTO, either as part of the RTO or as an equally independent organization, needs to have a body that can credibly and legitimately within a reasonable timeframe assess what used to be called integrated resource planning. At this state it amounts to high value choice, to say whom it thinks is qualified to collect the cost that will be socialized and collected through an uplift charge. Ideally, a credible description of anticipated need results in multiple offers for review. If that does not occur, we are back to deciding who is the provider of last resort, and that is very close to saying that we really cannot deregulate transmission because we have to go outside the market to meet the need.

Question: Then does the RTO perform the RFP function?

Response: Yes, as long as you have eminent domain and a taking and a need to justify them by the greater public good.

Question: Does the RTO have eminent domain authority?

Response: States rely on expert testimony in the proceedings before them. The RTO is an extraordinarily credible witness in such proceedings, but it doesn't have the authority. It has the position that it presents.

Comment: In most states, eminent domain authority comes by virtue of being a utility in the state. In a few states it flows out of the siting process. That may be better from the position of public policy, but legally it is the minority position.

Speaker Two

I will talk about the Southeast with respect to RTOs and SMD. At the federal regulatory level, they are becoming inextricably intertwined. I think there is a perception that regulators in the Southeast aren't interested, or aren't working on it. This is inaccurate.

The region is dominated by and the load is served by vertically integrated utilities. Most wholesale purchases are made within the control areas and there is no deregulation, maybe with the exception of Virginia, in the overwhelming majority of jurisdictions. There will be no retail deregulation in the foreseeable future and probably not in our lifetime. Many commissions have commented formally on interconnections, Grid South, SETRANS, standards of conduct and both the working and options papers on SMD. The Southeast also works with the Department of Energy and the National Governors Association on a transmission task force. The hard issues will be worked out politically and in Washington, and the region is trying to do a better job of coordinating at the state and federal political levels. FERC has told us that it wants the region to tell the commission what Grid South should look like. In the past it was the other way around. We have said that we will move forward on SMD and the RTO structure and then see where we are down the road.

But while progress has been made, it has to be put into its political context. In the deep South where lots of gas is located and many merchant plants might be built, if you are going to haul that power out in a way that raises the retail rates in the region, you need to understand that the commissioners there are popularly elected. Their positions are often steppingstones to the State House or other places ambitious people might want to go. There will be a lot of political resistance to doing anything that passes costs through to those retail ratepayers without serving them. This is the reality of the region. Commissions also have limited resources and must deal with telecom, transportation and other issues.

There is concern about the relevance of some of these issues to the South and an awareness that other parts of the nation have expressed interest in region-specific solutions. We presume that if the South had a lot of the problems that led to the development of tight power pools in the nrtheast, that we would have them, too.

In general, Enron, the California crisis, Texas, trading or discussions of economic theory have to occur in the context of the politicians, citizens and retail ratepayers in the South. For example, does North Carolina need to take the risk at this juncture when it has relatively inexpensive prices, good reliability and so forth?

There is a difference between pioneers and settlers. Pioneers, for whatever reason, choose to pursue risky ventures. They endure. More arrows are shot at them. They are probably successful to a greater or lesser degree. Settlers wait. They incur or assume less risk. Settlers, for whatever reason, do not feel the need to go first. They have fewer arrows shot at them and probably make fewer mistakes.

The South is not against vibrant wholesale markets or other regions doing what they need to in this regard. But there is a balance. There is concurrent jurisdiction between the federal and state governments. The South will fight along that battle line on the things that are important.

Question: Is the new generation primarily merchants or is it the utilities?

Response: The projects actually coming out of the ground are investor-owned and I think that all of the merchant plants are probably a little further behind. In North Carolina, for example 90 percent of the load is not dependent in any way on the wholesale market. It would be difficult to prove that there is undue discrimination or that the potential benefits would be that significant, given this structure.

Speaker Three

The Midwest has cooperated with FERC in working through issues of RTOs and SMD. But working on a regional basis is an unnatural act for many state commissions and logistics and geography make it difficult to get together. We are trying to figure out our regional differences in standard market design. For example, the Midwest probably uses more coal, has less hydro and until new plants come on line, the use of natural gas has not been as great as elsewhere. Load density is lower and we tend to have remotely sited generation. Finally, with the exception of Illinois, Michigan and Ohio, most states have not restructured. To come up with something in the Midwest means we will have to accommodate those states.

Each state filed its own comments on SMD at FERC. The Midwest is reviewing the comments on the options papers to see if there is some consensus from the positions with which FERC can start to build something. We are also trying to determine the basis for the areas of disagreement to help us figure out what kind of SMD will work for the Midwest.

What incentives are being provided to stimulate investment in new generation and/or transmission, and what use is being made of rate-based treatment? Three years ago, restructuring came before the Iowa legislature and was defeated, although it probably got as close as one can to passing. Next, a commission study found that capacity would be needed as early as 2003. The legislature then passed a bill to incent the utilities to build generation and streamlined siting. It rejected least cost, saying the utilities should build when it was reasonable, compared to other alternatives. The bill also gave the utilities the opportunity to come to the commission for up-front advance ratemaking treatment. In other words, it changed the traditional regulatory structure.

Two gas-fired combustion turbine plants and one large coal plant have been announced, all of which will be rate-based. That will be the control group that everyone can look at to see if this is the better way we have been trying to create in the last five years.

For me, it is a question of how much pain you are willing to endure along the way to getting a change in structure. The legislature is unwilling to put up with the uncertainty that is related to the change. It would rather have certainty – putting new plants in rate base -- even if one makes the argument that it will cost more right now.

As more transmission is needed to alleviate system constraints, siting will become more important. The difficulty is that we operate in a federal or a state system and do not have mechanisms to deal with regional levels. As we have begun the move from a regulated to a competitive model, several things have changed the adequacy of state control of siting. One is mergers. Now we have regional utilities, regional power producers and national players. Competition in the wholesale market, Order 888 and the move to a competitive model in retail access caused the need to move power on a regional basis. Our transmission system was not designed to move power regionally or in a competitive environment. Now we need to be able to site lines within a reasonable time period.

People understand the importance of their particular state's resources. In a state like Iowa, it means topsoil and agriculture. There is certainly a threat when you talk about the need to move power and to have transmission lines built fast. For many people, that means turning over power to the federal government. States are understandably very averse to that happening. We have to find a way collectively to streamline that process, whether it is an interstate compact, voluntary cooperation or creating regional regulatory bodies. Interstate compacts are burdensome and take a lot of time. A memorandum of understanding signed by governors could help develop a regional record. It would still come back to the states for actual siting because I do not think that authority can be delegated to a regional body. There will be pressure on the states to make a process work because the first time that there is an agreement that a line must be built and the parochial concerns defeat the line, there will then be pressure to remove that jurisdiction from the states and give it to Washington. Since the federal government already does siting for natural gas pipelines, there is a model.

On the issue of the Supreme Court's decision on New York vs. FERC, I think that the recognition that a lot of markets are regional and national is behind the push to have standardization for easier entry. The relationship between wholesale and retail markets calls for a cooperative federal/state relationship, not just an out-and-out transfer of power to the federal government. I think there is potential for FERC to take a lot of jurisdiction under the case as it stands. Does FERC have the right to order the expansion of transmission? If you believe you have the right to preempt, you will have a jurisdictional battle with the states and it will take place in the courts. The courts are not a good forum for resolving these issues. A better way is to work cooperatively and figure out whether something is best done at the federal or state level.

Speaker Four

My vision of how the electricity system should work in the West is a regional vision with a regional market. The Committee for Regional Electric Power Cooperation, or CRPC, includes all of the public utility commissions of the states, regulatory commissions of British Columbia and Alberta, state energy offices and also the governors' and provincial government offices. CRPC is a subcommittee of the Western Interstate Energy Board, which is a committee of the Western Governors Association.

General concerns in the West are that SMD may distract and divert resources from ongoing efforts to get RTOs up and running, because there is a scarcity of people who are knowledgeable in these fields, as well as a scarcity of money and resources. Another concern is the interface between SMD and the RTO proposals developed to date. Which is the trump card if the standard market design is different from the RTO? FERC's answer seems to be the RTO. A third concern is the need to acknowledge and accommodate legitimate regional differences and needs, for example, our hydro.

In the Northwest, about 60 percent of load is met with our hydro system. Bonneville Power Administration has commented that centralized operation is incompatible with the hydro system because of the need to continue the current system of economic dispatch with its interdependent operation by different owners who all share the same fuel. The numerous non-electrical demands and concerns include fish, transportation, recreation, and flood control. The way the system is used is not always for the benefit of the electrical needs of the customers in the region or subregion.

The transmission system is composed of extremely lengthy distances since generation is for the most part, very remote from load. When we talk about the different systems and their operating characteristics, size does matter and we are quite large.

Financial concerns include the statutory obligations imposed on BPA by Congress, including preference power to certain categories of customers at cost. And RTO West has proposed a variant of LMP that is a voluntary, bid-based system for clearing congestion. I think some people have commented that LMP works well with a tight pool and thermal resources. However, there is a considerable amount of variation in our system by season and time of day, and from year to year, based on what kind of water year we are having.

There has been a very active wholesale market for decades, mostly on the basis of bilateral contracts. What do you do with people who have contracts and think they have rights or obligations? How do you meld that into a new SMD? And are federal agencies intruding in areas that have been and are legitimately state jurisdictional issues?

Siting is important in the West. The Western Governors Association organized a study that led to a conceptual plan for electric transmission. There are two models. What is needed if all new generation is mostly gas, and what is needed if you consciously set about to have a diversified set of resources come on line? The answer is that you do not need more transmission because the assumption is that gas will be built near to load and won’t strain the existing system. But you will need many billions of dollars of investment to get generation from resources to load if you want to have a diverse portfolio of assets coming on.

One refinancing model discussed is a subscription-type, similar to the gas industry. If a line is needed, the people who think they can benefit from it subscribe, finance and build it, thus essentially using and owning it. The other model is the total system cost, or average pricing model. If a line has system-wide benefits, spread its cost throughout the interconnection.

Now assuming you identify need and how to pay for a line, how do you site it? The latest draft of the Western Governors Association siting protocol states that its purpose is to establish a framework to enable affected states, local governments, federal agencies and tribal authorities to participate in a systematic, coordinated review process for siting and permitting interstate transmission. You may not realize that if you siet anything in the west, you bump up against federal lands. Idaho is 65 percent owned by the federal government. You often deal with the Forest Service, Bureau of Land Management and other parties, whose processes are excruciating.

The federal agencies are expected to sign onto the protocol. We recognize that other entities are not insignificant and that we need a central point where information can be collected and disseminated to the project developer and the numerous parties.

Where does the planning responsibility lie for expansion or upgrades in the western interconnection? The Western Systems Coordinating Council is now the Western Electric Coordinating Council. It is no longer entirely a stakeholder board, but a 27-member board. Its vision is one interconnection-wide organization that would do reliability and take on issues done by previous regional transmission associations, such as market interface issues. If Congress passes the legislation, this organization will be delegated by FERC to oversee reliability.

The debate about whether the new organization does planning or planning remains with the RTOs is one that the region will have about how to plan needs in the future. Another organization is the Seams Steering Group of the Western Interconnection. For a year now, we have tried to make sure that the filings that the sub-regional RTOs make at FERC are consistent with each other and can actually operate together.

Demand response clearly remains state jurisdictional in places that still have fully bundled services and integrated, regulated utilities. Where there is retail access, there probably is a compatible state and federal role, so they do not undermine each other. Some of the biggest opportunities for demand response are with irrigation customers and summer-peaking utilities, where irrigation is the load that drives the response.

I agree that states should review programs and opportunities, and each must use its own tools and apply them to their different customer classes. Perhaps FERC is not as well situated to understand local concerns and deal with the differences. What would cause the West to go to battle would be the required divestiture of its hydro resources.

Question: Are you proposing an uber-RTO for the western interconnection that would manage both planning and reliability?

Response: The debate is ongoing. WECC exists now and we will not have RTOs for several years. We probably need transmission and we need somebody to plan for it.

Discussion

Question: Under its jurisdiction to expand transmission, suppose FERC orders expansion. It is a long, arduous process and the states decide not to grant eminent domain. What happens next?

Response: You asked whether the fact that the Act speaks about authority to order expansion of transmission means that FERC has the right to preempt the states. A partial answer is that there would be a big fight and FERC would lose. The reasons are relatively straightforward. But first, I think that if the goal is not jurisdiction but is a good end result for the country, FERC can win in a different way. Jurisdictionally, a court reads a single clause of a statute together with the overall statute. For example, the Federal Communications Commission thought that the statute that said, “Run an auction for wireless licenses” meant that the FCC could do whatever it needed to. It ran into the bankruptcy code. FERC got into trouble 30 years ago when it thought that the authority to produce electricity from hydro sites meant that the commission did not have to worry about NEPA or agricultural usage.

The legislative history says that there should be an invasion of state interest only to the degree necessary to achieve several purposes. I do not see a clear demonstration that is a Congressional intent to give FERC the authority to overturn a century of state siting decisions. The transmission expansion language can be read as a more limited purpose of ordering the transmission owners to be willing to make it to the degree that they are allowed by otherwise applicable law.

In practice, frankly, you find that it works better than you feared. An example is a transmission line that leaves Montreal, runs through a third of northeastern Vermont, a third of southwestern New Hampshire, the western third of Massachusetts, feeds into something that had to be made larger to feed southwestern Connecticut. On its face, the line had no value to Vermont, yet it was approved in 1982 and built in 1983. It was challenged in a Vermont proceeding the way it was in other states. It was approved under a logic that said that even if there was no direct state advantage, the strengthening of the grid from which all states drew their power was part of the general good. The logic was based on a legal analysis of the general good and the intent of the people who passed the statutes, and on a pragmatic quote from a farmer who appeared at a public hearing and said, "If we're going to sell our milk down country, we want them to be able to run the refrigerators to keep it in."

People do recognize a common good. Where there have been problems, they have been as limited as needing to avoid the oyster beds in Long Island Sound by rebuilding a transmission line four miles from where the line was first proposed. Generally, the problems are not of constitutional significance needing a Supreme Court case to solve. They can be solved by common sense and goodwill.

Question: If there are merchant plants whose purpose is to serve a region, isn't there a competitive issue that needs to be solved to make sure that they have equal access, and that the utilities that have generating plants and transmission are not utilizing that transmission to inhibit the market or to benefit themselves at the expense of the merchant plants? Does that necessitate some kind of RTO or market design?

Response: In North Carolina, the interest in merchant plants has little to do with serving the existing load. It doesn't mean that over time, as retail-based generation comes offline, it may not be a solution. Economic development is really the ability to bring some investment to the rural areas where gas transmission and cheap land coincide, at least from a regulatory or political perspective. The regulators' job is to elevate the service that the merchant plants enjoy, but not at the expense of the retail ratepayers. We are not having trouble getting any interstate transmission built to serve load within the state. At present there is no evidence that problems exist or that there is a need to build such transmission.

Question: It appears that you have a potential competitive disadvantage for the merchant plants in the southeast.

Response: We ought not to allow a merchant generator in the state access to the transmission grid to the detriment of retail ratepayers.

Comment: If you have merchant plants, you have an issue of how to make the wholesale market as competitive as possible without giving market power to the utilities that own the transmission system.

Response: I do not disagree. But if FERC tries to get into things like controlling dispatch under the guise of SMD, that will be an issue. In other words, is standard market design a back door to achieve indirectly matters that might be more difficult to achieve directly?

Response: It's important to understand how significant some of the SMD rules might be for the resource mix that is built in states and in pools. In FERC's white paper there is a discussion about what FERC calls the legitimate start-up costs of baseload units with long ramp-up and shut-down times. If there is a market need for power for four hours or four days, but the unit that can provide it needs eight hours to get started and eight hours to shut down, the market price will cover the four hours during which there is a need, but the ramp-up and shut-down times can be put into a pool that will be socialized. This matters because if you are running a coal-based plant or a nuclear plant, you can take a large amount of your operating costs and have everybody pick it up instead of having it assigned to your direct sale. This is a simple example of something that may have a huge impact on whether one builds a combined cycle plant which ramps up and shuts down quickly, or a baseload plant that starts up hard and shuts down over a long period. The decisions that are folded into the SMD rules are the same decisions that states worried about in integrated resource planning. Having these decided at the federal level is a scary prospect, but they are less important than the need to get demand response into the market. What is clear is that in the nuts and bolts of SMD there are issues that substantially alter the incentives for how things get built and how they will be dispatched.

Comment: You can avoid those charges by self-dispatch and by supplying your own ancillary services so that you will not be responsible for the charges if, in fact, you do not use the grid's ancillary services.

Comment: I have read the paragraph and the footnote four times. That concept does not emerge. The problem is not what the buyer has to pay, but what the seller gets to spread around. Seeing that the buyer doesn't have to pay it in its direct purchase doesn't solve the problem if all the buyers collectively pay it through an uplift charge. When it says, "The generator may have legitimate start-up costs that are not fully covered by selling at the hourly energy price over the day, and paying uplift may be necessary to ensure the generator is selected," it sounds like spreading the start-up costs over the pool.

Comment: People are not building plants in the West or in California specifically, not because there is a capacity surplus, but because of uncertainty from a regulatory perspective, at least in California. On the demand response issue, if a smelter on the Columbia River decides not to run in order to provide its power either to other places in the Northwest or within the region, how is that taken care of? With respect to some of the metering issues and some of the state-related retail issues, where they are located has impacts or opportunities on the overall wholesale markets. How do these issues filter up from states into the larger wholesale market?

Response: The retail price signal should reflect the impact on the pool, whether or not the smelter is run. The two elements to that are the energy charge and the capacity charge. It would be nice to have a simple rate that said, "Here's the energy clearing price." But in reality there are two dimensions and you can't ignore either. You need a price signal that goes to somebody at least as big as a smelter or an aluminum plant, and that gets both concepts across. You have a time frame over which to spread the capacity charges, or you have a ratchet. Since the ratchet is the total pool and not the individual plant, it's a little difficult to give a signal that predicts whether they will hit the ratchet. It is probably better to spread it over time and wind up with an installed capacity charge. I don't like the current mechanisms that have been used for ICAP because they reward past decisions instead of incenting future decision-making. I haven't got a good answer, but the solution is how to enable the person running the smelter to make a decision influenced by its effect on the overall impact on the pool.

Response: If the smelter customer is in a state that has retail access and has a contract, you can use the contract's provisions to say, "I own this much power. I can sell it back and I will get some money for it." If the smelter is in a state like Idaho, then it will happen the way it did in 2001. When we saw a shortage coming, the customer and the utility told the commission that it wanted a load reduction agreement put on as an amendment to the existing contract. The regulators considered and approved payments under that.

Response: After all of what has occurred in California, we still do not have a mechanism for ratepayers to control their energy use with real-time meters and rate design to reflect the usage. There is a benefit that can accrue to an overall wholesale market by having a response to that mechanism. This seems to be within the jurisdiction of state commissions.

Comment: Regardless of RTOs or SMD, there are many good ideas that regulators try to pay attention to and things that ought to be done better. To the extent they have benefits for the wholesale market, regulators ought to feel obligated to do these.

Comment: A major impetus to go to a competitive wholesale market is largely due to the flight from capital of the IOUs. The largest utility in Oregon 20 years ago generated or bought on very long-term contracts probably 90 percent of the power that it sold. Today, it's 50 percent. And that goes back to the days of the disallowance on nuclear plants and calling into question major investments that turned out to be unneeded during the recessions of the 1990s. At some point, though, we need to stop changing the system so investors have some level of certainty. I am almost indifferent as to whether we go back to the old system of vertically integrated, widows and orphans investments, or go to cowboy capitalism of a fully deregulated system, as long as the rules are known and we attract investment. Energy efficiency and renewables are very high capital cost items. We've been lucky to have relatively cheap natural gas plants. Recently there was a proposal to spend $1,500 a kilowatt on conservation programs that were cost effective. But that's because 100 percent of the cost of those programs is capital.

Response: My tentative observation is that there have been two changes in access to capital. One is the relatively big – at the time – and relatively small -- as it looks now – degree in the increased difficulty of getting capital after the round of nuclear power plant disallowances. The second is the literal flight of capital from the equity markets for the industry, beginning with California in 1995 and rapidly accelerating in 2001. Every impression I have is that there was a moderate increase in difficulty in access to capital in the early-to-mid 1980s and a radically different increase in that difficulty in the last few years.

Response: Implicit in your statement is an either/or model. Some of the companies with which I work are taking advantage of unregulated opportunities and seem to be doing well in terms of a flight of capital and an absence of capital difficulty. North Carolina is approving significant financing, or recommending working with the SEC on the approval of significant financings.

Comment: We passed the Energy Policy Act to open up the transmission grid so other people can use it. Then came Order 888. Almost immediately, the North American Electric Reliability Council adopted transmission loading relief procedures because what happens in one place affects everywhere else and cannot be avoided. Next, we needed to manage the process. We got into the RTO debate. Now we have the Supreme Court order that recognizes the physical reality that 90 percent of your native load that is not in the wholesale market uses the same wires and they are all interacting. I think there is nowhere to hide. In fact there is a wholesale market. There is access to the transmission problem. It can't be avoided if you're connected to the grid. Now we need solutions to that problem. There is basically only one demonstrated way to do it and everything else is just trouble brewing or waiting. Can we do something that is fundamentally different from what is evolving as the standard market design? It can't be done without the cooperation of the states. I think that physics drives this story. We desperately need the states to cooperate with FERC to get this right because eventually the problem is going to boil over.

Response: Timing is an issue, too. I think it is not telling the states that there will be four RTOs but soliciting the role of state regulators, not as stakeholders, but as concurrent jurisdiction. In a legal sense, the physics are that FERC's jurisdiction is limited. Where that is we may quibble over. But the reality is that we have different parts of one ultimate service or commodity that is provided. The physics I am most concerned about is the need to work together, not to dictate to one another what we are going to do. There are parts of the country that naturally – because of geography or economics – are working out these problems. The difference for my region is whether we need the risk. We will be cautious because we can afford to be.

Question: If market participants should not determine the governance structure of an RTO or an ISO, is that an endorsement of a self-perpetuating board?

Response: Who will guard the guardians? Obviously the concept of a self-perpetuating board reporting to no one is unsettling, if nothing else. I think FERC has to be the guardian because of the general public good. The only thing worse than having an unresponsive, autonomous, self-perpetuating board that is random in its behavior is having a responsive board that is controlled by a body with an interest in a subset of what a market should do. If I had to choose between a board controlled by people who benefited from high prices and high throughput or an independent board, I'd pick independent because random is better than skewed. But if the choice is to have it overseen by FERC, I would like the latter.

Question: Demand side response, supply, whether we should put load in areas where there are constraints, or build new transmission to relieve them, all compete. Impediments we face in making the system work, particularly on demand response and to a lesser degree on supply in the wholesale market are price caps and the fact that we have regulated rates in jurisdictions that haven't gone to retail. We must structure a market based on regulation, without the ability of customers to experience real demand side response pressures. Now the generation solution for ISOs and areas that are working toward RTOs has been the overall solution in the marketplace because transmission is so difficult to subscribe, build and operate. Given the limitations, can we design a smart standard market design, or are we supposed to solve the problems before SMD? Many parts of the country have to develop their wholesale markets from scratch or face other issues. Are you moving forward or are you between a rock and a hard place?

Response: We know that one and a half percent of customers and two and a half percent of load have made a choice and everyone else is either a tariff or under a standard offer which, for all practical purposes, looks like a tariff. I like to think of this as an opportunity; if we can make wholesale generation into a set of incentives that get some technology enhancement and incentives for lower-cost production, there is a big payoff. I only caution that you need the moral courage to say at some point that you are in charge of the light brigade and your job is not just to charge forward because you think it would be nice if you won. When you are spending other people's lives and money, you need to assess the probability of success and think about whether it's actually going to be achieved, not just how desirable it would be if you pulled it off.

Response: I understand very well that there is risk in doing nothing and in being too content with what you have. I also appreciate that there is a lot of risk, as the people in California and elsewhere will tell you. It is an exciting dilemma with bright people on all sides of these issues. I am grateful to be somewhat in the middle of it.

Response: There was good reason for the states that first went to retail access to do so. Some had rates that were unacceptable and they saw the rates elsewhere in the country. I think about the change in the gas system and deregulation at the wellhead, with everyone benefiting from that for a number of years until we ran into the supply/demand imbalance a few years ago and prices went through the roof. That had a huge impact on people in states with very, very cold winters, people who bore the brunt of those increases. In a situation like that, one sits back until there is a compelling reason to make a change to the system, preferably after others have shown how it can be better. But we should not forget that the development of a certain market design is not a goal. It is a tool to achieve a goal, which is the provision of adequate, reliable and reasonably priced electricity to all of the customers who want to use it.

Response: We have to keep looking at the evidence. A year ago, FERC said, "Well, this is okay; don't mind California." Then it was, "Don't mind California and Enron." And then, "Don't mind California and Enron, and Pennsylvania is a little sluggish and Texas is a little sluggish and Virginia is a little sluggish." Now it's, "Don't mind all those other things. And we'll work around the trading." The jury is still out in reading exhibits, but that list of exhibits is getting longer.

Question: You try to collapse many control areas with disparate rules into one area. If you advocate that the expansion of the grid should be open to all players instead of just the transmission owners of today, there ought to be third parties that invest in the grid. This suggests that we are moving toward a balkanization of transmission ownership of the grid. What are the benefits of such an approach and are they really worth it, given the risks of actually moving from what we have today? The benefits may not offset the risks of going forward.

Response: I see some value in having a body larger than the states and more knowledgeable and responsive than FERC that can legitimate a claim that a proposed transmission path serves the general public good. I can visualize the RTO/ISO being that body. Conceptually, having an open door to an entity that wants to risk its own money and put together a line is fine. In practice, the number of parties that can actually buy all of the linear feet, yards and miles needed to connect one place to another without invoking the power of the state is slim. Mostly, I view this as an issue that is exciting conceptually, but that isn't going to be a big matter in terms of solving this country's problems for a few decades.

Session Three. Beyond Slicing and Dicing: Incentives for Transmission Owners

A standard market design provides the basic framework and tools in support of a competitive electricity market. But the standard market design does not provide a complete solution or every tool needed to achieve the policy objectives. As that debate moves behind us, the next level of policy issues can receive attention. Financial transmission rights can support merchant investment, but are inadequate to address the problems associated with large economies of scale and free riding. What are the incentives for transmission investment in the presence of market failures? What can be done to define performance objectives and provide incentives for transmission companies to meet those objectives? How can innovations in maintenance practices be encouraged? How can risks be defined and rewarded for transmission companies? What incentives and institutions are needed to complete the package to make an independent transmission company a viable business in a competitive market framework? Are FTRs a sufficient or even an appropriate incentive for transcos?

Speaker One

The American Transmission Company began operations almost two years ago. Its service territory is the upper peninsula of Michigan, most of Wisconsin, and a little bit of Illinois. The formation of the privately held company required the divestiture of assets by for-profit IOUs and also by cooperatives and municipal companies. They divested their assets, invested in ATC and got ownership back. What is interesting about becoming a transmission-only company is the impact of having a single focus. First, everybody looks like a customer and it becomes clear that the company is a utility. As such, the company bears on the public interest. It is FERC-regulated. However, ATC does have to deal with each state and their peculiarities.

The company's purpose is to be the means to get to the market. There is no competition internally for the use of its financial resources. As a single-purpose company there is no difficulty financing transmission. The business plan includes a public involvement planning process that identifies the needs of the customers for ten years and forecasts the projects that can mitigate those needs. There are two reasons to go public. One is to be open to anyone who has an alternative way to mitigate those needs so that we do not build if the need goes away. The other is to make sure that everybody becomes very familiar with the needs, and it is not a surprise to regulators, landowners and the public when the company has to file.

The first year of operations, we built about $70 million of new assets. In 2002 it will be about $110 million and in the next few years it will stay at $200-200 million-plus and then begin to come down. Why are we building so much? The system is in very good shape; there's just not enough of it. Throughout the country there are some significant gaps. Some other problems also need to be solved, such as stability or voltage or old equipment. When the economy turns around or the summers get a little hot, there will be significant load nationwide. Frankly, we never considered the area we serve to be congested since we were operating our own generation. Now that we are trying to operate nation-wide, there is significant cost involved in re-dispatch, and we have the right to re-dispatch and we socialize the cost.

There is tremendous turmoil right now, not just intellectually, but among states and local entities and companies. We all need to remain profitable and for that we need a stable regulatory environment in which we see a pattern of decisions by FERC. It is my opinion that the regulatory environment is not propitious to incentives

in a regulated monopoly. I think that both state and federal levels are uncomfortable proposing incentives. Adequate cash flow is important because it gives comfort to potential lenders. When you break up companies the transmission system fits with some investors better than an integrated company because there is a different income stream and risk profile.
The biggest obstacle for transmission is dealing with the public. The best case we have is to tell the landowner and the public that a line is needed by a variety of people, including people like them, or is unavoidable because even though they might not need it, the people at both ends of the line have a right to be served. That reflection of public good appears to be just about the only thing accepted as legitimate in the public forum. The best description is that we are running a political campaign twelve months a year, with all the features of political campaigning, including polling specialists who have peculiar tools like enemy assessment. The reason is simply that we have to find out who we are talking to, what their issues are and how to sell them on the concept that the proposed line is a good idea. We also have to find different ways to compensate people for the use of their land, which is a very legitimate issue.

Basically, we have not yet come to the point in this country that we have enough stable transmission so we can begin tweaking the edges. We need sticks in the mud and wire between them. Otherwise, we're not going to make it.

Question: Do states have separate siting authorities with different standards of what a public need and public good are when you have to build transmission upgrades that may be sited in one state but will affect some of the surrounding state?

Response: Most of the transmission needed for regional access happens to be across state lines. Today, you have to have two processes in every state for every project and the project's opponents can take it on for different reasons in each state. Many states do not allow you to use the need of an adjacent state as the reason for building something. This has to change. One day you may think you are in the winning seat. You are a regulator in a state and you say, "We have plenty." The next year you may be begging. It's a bad idea to be depending on something where you cannot influence it and in fact the rules prevent it. If I find any reason for a federal back-up, it's this. The need must be something that must be agreed to in both a regional and federal fashion.

Speaker Two

I will focus on the role of financial transmission rights (FTRs) in providing incentives to support merchant transmission investment. I'd like to avoid arguing that if you think merchant transmission investment plays a role, then only merchant transmission plays a role. I don't think that is correct. There are many problems that we must address, such as inefficient transmission investment, economies of scale, free riders, incentives for grid owners and planning roles. I am particularly interested in how FTRs interact with market-driven investment. There must be simultaneous feasibility in order to maintain revenue adequacy to meet the obligations under the FTRs.

Now we want transmission benefits to go along with transmission costs. In some cases we can identify the beneficiaries or some of the benefits and they can be assigned in the form of FTRs. In other cases we cannot. I don't think there is any perfect solution to this problem; we have to remember that we are making tradeoffs. Free riders may force a residual role for monopoly investment, even if you do have a lot of merchant investment.

The idea of FTR allocation is that you would have financial transmission rights to the grid, like the point to point obligations that have already been implemented in PJM and New York. The feasibility test is that the aggregate of all these rights defines a set of net power injections in the grid and the set of contracts is feasible if these injections and their associated power flow satisfy all the system constraints. The feasibility rule is that if you expand the grid, then the grid expansion investor selects a set of new financial transmission rights, with the restriction that both the new and the old FTRs will be simultaneously feasible after the expansion.

This guarantees the revenue adequacy going forward. The rights that you allocate today for ten years hence you can be confident that if you follow the rule between now and then, that you'll have enough money to pay for those rights. An important feature is that future investments in the grid cannot reduce the welfare of aggregate use according to the existing FTRs. One of the problems in the literature is to make sure there is efficient investment – that people don't do things that reduce grid capacity. This turns out to be a bit tricky. If you say, "We are not going to remove any capacity that anybody might ever want to use in any spot market configuration," that is a demanding standard and it also may be impossible to meet.

The people who will be exposed to future losses because of a change in the grid are people who have not hedged. In other words, they have decided to rely only on the spot market. So you can isolate it at least to them. I would argue that it is difficult to imagine a market that protects everybody including the people who do not choose to be protected in the investments they make in the grid.

Bushnell and Stoft have defined a set of restrictive conditions (FTRs have to match the dispatch, but won't always do so) that says if they do in a particular way, then there is never an incentive to do anything that is inefficient economically. In fact, you get the right incentives to make the investments and to match the FTRs.

Conceptually, if we had a grid and long-term FTRs – for the sake of discussion, let us say 20 years – and we had sold off the rights to the entire grid, we can have investors buy incremental rights if they want them. We award them as a result of the investment. The investors can have anything they want as long as they are simultaneously feasible with the existing long-term rights.

The reality is that we do not have 20-year rights for the whole grid. The longest ones I know about that are under discussion in New York are about 5 years. In most places it is even shorter, which reflects the nervousness about this and the transition period that we are in. New Zealand actually wants to have a transition where it will never have FTRs that last more than a month and they'll be auctioned off monthly.

What about investors who want to receive 20-year rights? Figuring out the increment when you don't know the base is a problem. We can think about it first by using the feasibility rule. We will expand the grid. Whatever long-term rights we have – and zero might be possible – the increment awarded the investor has to be feasible with the long-term rights after we make the investment. Second are proxy awards. A specific set of rights in the existing grid should be preserved as proxies even though they actually aren't awarded. Combined with the existing rights plus the proxies to protect the existing grid means that the increment must be simultaneously feasible with the sum of all of those things. Third is maximizing value: the investors who are making the choice ought to get the award of the incremental rights that they want most and they can specify what they prefer. Fourth is symmetry -- the expansion protocol that should apply to both increases and decreases in grid capacity --to figure out the incremental rights.

The difficult part is to figure out the proxy awards. Initially it was thought they could somehow preserve everything on the grid, or a lot of everything on the existing grid. Analysis showed this was not such a great idea. Under this rule, a non-zero incremental award of FTRs could require adding capacity to every link on every path in the mesh network. This would virtually preclude investment on anything other than radial lines. Not as obvious is a rule that the best use of the current grid along the same direction would be only the proxy award. We are not protecting everything. We look in the same direction that the investor wants to receive incremental rights and say that we want to save all those that we can get out of the current grid. Then we will give the investor the incremental ones that can be added of that type. There are some criteria for choosing the best under the proxy awards. You can set up preferences that give you an auction model. The FTR auction in New York, similar to PJM, has bids to create a preference function. The difference is that it is the preference of a single investor to trade off among the different FTRs that it specifies. The questions to ask are if this provides good incentives; how we solve the software problems; and do we like the awards.

One point about any kind of investment in the grid is that it makes some things feasible and some not. The notion that we are just going to increase throughput or something like it is not the way the system actually works. You have to solve this problem if you haven't fully allocated the grid.

Other questions deal with the incentives for transmission owners and ISOs. I don't think we have the full answers. I am suggesting that some of our ideas can present a set of tools to use to craft those incentives.

Question: Say a new generator comes on line and the increased value at risk output capability makes incremental FTRs possible above and beyond the feasibility rule and the proxy awards. Do you envision a market so that a generator could receive FTRs if its value at risk is supported at all times and is penalized when they are not?

Response: Yes. The longer answer depends on how the constraints are implemented. Do you have an AC model like New York, or a DC approximation like PJM? Does that get translated into interface constraints, as opposed to a thermal limits problem? There are many technical details to work through.

Question: Will even the addition of a small parallel line significantly alter the transmission capabilities and rights?

Response: It alters the pattern of flows throughout the grid. But significant is an issue and some things are bigger than others. It doesn't affect point to point FTRs -- the obligations that are in PJM and New York -- because they were designed to make sure that it wasn't dependent on a particular pattern of flows. You have to preserve the feasibility tests. In addition there is another conversation about investment in flowgates and flowgate rights.

Question: If you receive an FTR could it cost you if the line that you add to the system is in fact out of service?

Response: If you keep the feasibility of the system intact, then it is always revenue adequate, but not if you lose a line. Just like with physical rights, if you lose the line, you cannot do what you did before. How could you use this to provide incentives for good maintenance or timing of maintenance? I have heard of places where maintenance is scheduled from noon to five Monday through Friday because of convenience, and there is no financial penalty on the transmission company for doing that. However, the market doesn't work that way. Suppose you wanted to get a market incentive. One idea would be that if the line is down, the person who has taken the line down has, within some bandwidth, an obligation to pay for the compensating FTRs that restore the revenue adequacy of the existing FTRs. If you do that, you have to have the symmetry rule, which is what happens when you contract as well as when you expand.

Question: PJM is considering going to options as opposed to purely obligations. How is this affected?

Response: I think it makes the arithmetic more complicated, like it does with awarding them in the first place.

Speaker Three

I think we may all have a different way of framing slicing and dicing. If operating the system means operating the market, and all of the market functions are with the RTO that is the ISO, then the grid owner could be an ITC, a more traditional ownership of the vertically integrated utilities, or the unbundled utilities or any kind of merchant ownership. We no longer worry about the organizational construct. I think that helps us move forward.

The incentives for the asset owners will be much the same once we re-frame the arrangement that way. I think about how the transmission business is in the spot where generation was about ten years ago. People said, "Oh, we can't possibly have competitive generation. It belongs in the vertically integrated utility." Then we saw a few IPPs and some EWGs. Now we see whole companies having divested their fleet of generation assets to compete as a competing asset.

This is where we are in transmission now. The naysayers say, "This can only be one way." But where we have LMP, there is a different way, because we have now revealed the prices, the spot value transmission being the difference between the two points. We now know what transmission is worth. We no longer have to have the debate about not building enough. We build only what we need and the prices show us. We now have a lot of background data for a cost-benefit analysis when somebody argues that all the benefits go somewhere else. We can show what the benefits are and we can also lower the barriers to entry for new generation.

Again, if we look at generation, in the long run most of it became competitive, and it became a business of best managing assets in order to capture their market value. Generation-forced outage rates have gone down because there are ways to get the money.

Another aspect of reframing is property rights in the form of FTRs. Without them, we have something that's socialized, and we don't really know its value, or we have something that we have paid for with an upgrade on the grid and we haven't received any rights or any value for it. That is not a model that sustains investment.

I call this liberating the grid owner. We no longer have to worry about the "i" in independent or the independent functions because they belong with the independent entity. Grid owners no longer have to worry about the onerous demands and restrictions on how they can form financial coalitions to attract investment. As transmission owners, we want to capture the economic value along with anybody else. So generators can site in a place that provides counterflow, which is like making more grid capability available. Or we can expand the grid to make capability available. Or we can take demand off the grid. These three competitors do not operate the market, nor should we assume that transmission owners should because they are now competitors once we go to LMP.

Two problems must be solved as we move along. One is how to capture the value in the existing assets. Assuming that consumers paid for most assets through rate base, then the consumers need to capture and hold the value that they have already put into the grid. Can we now do this through FTRs? Even though the FTRs may only exist for a month or whatever, I think in the PJM model that they exist for the life of the asset. But they are subject to an annual reallocation. When trying to look at long-term investment, it might be helpful to have three-year or five-year property rights. But the rights are always there – they are just reallocated to LSEs on behalf of consumers.

Next is how to incent grid owners to do better in the operations arena. This is the real-time, day-to-day management, how to operate it wonderfully. When I talk about operations I mean that the ISO as the RTO controls the grid, yet the local transmission owners have to be the eyes, ears and hands of the ISO because economies of scope are such that you need a hierarchical structure with the RTO sitting squarely on top, making the decisions. I am not talking about someone actually being in a preferential treatment controlling the market; the market rules are fair for both generation and transmission asset owners.

One reason we started competition, so I am told, is to capture the benefits of technology. Technology has improved beyond where we are today; you can re-string larger conductors or upgrade limiting components. There are ways to expand the grid beyond hanging all kinds of new wire in the air, although as a transmission owner, I like that option.

What is the new transfer capability once you put in new wires? We have already solved that as planning engineers. How we monetized it is done through LMP. With prices we reveal to the business public the mystery beyond what the system operators and planning engineers used to do.

If the FTRs represent the economic value of the grid, then we want to make sure that any practice, new investment, operations or planning actually help to capture the additional value for the market. This is the incremental piece that customers did not pay for in the embedded cost regime or the rate-based rate of return.

When looking at incentives, how do we make sure we have an incentive to work on weekends – which may require overtime – when right now the pay is the same? One way sets a benchmark level of FTRs and how many FTRs are funded. If the transmission owner does a good job maintaining the grid, then it gets to keep the money. New York does it through a formula rate, socializing the under-recovery. PJM at some point in time socializes it. We need to get away from socialization and put the under-recovery on those who created it. If we can say it is because the transmission grid was not well maintained or managed, then we tell the owners that they need to fund the under-recovery. The flip side is that if you have done a better than expected job of maintenance, making the grid available when it is valuable to the market, then you get to retain the money. This is how transmission outage rates go down and we improve the transfer capability through making the dollars available where value is created.

There are also companies that would like to see value from live line maintenance; they do not take the line out, but keep it available to the market. However, an incentive for off-peak maintenance is unavailable right now.

Can we use technology to carry more electricity on our existing infrastructure, and identify and improve the key bottlenecks? I don't think we need a lot of new wire hung in the air, because of the LMP paradigm. Once you reveal the prices, you really do see where you need new wire.

I also believe there will always be a reliability backstop because of stability and voltage issues. My guess is that the backstop will be under the more traditional rate of return. I think there will be a blend of merchant and regulated and that it will be important to separate those and make sure the property rights created by each type of investment go to those who paid for it.

I also think transmission owners can start bidding in the future on activities to relieve congestion. It might be switching load from distribution feeders. Flexible AC technology allows transmission to respond very fast, a lot like a load following generator within a congested area. An owner might be willing to expand a line for so many dollars per MW of transfer capacity. The owner is a market bidder who says, "Here is the value upon which I am willing to start doing a business plan. And if the market isn't going to give me that value, it is unlikely I will build the line or expand or make the fix." We do not yet have all the pieces that we need, or a good idea of deliverability rights and injection rights. What it comes down to is if I pay for something, do I get a right to it. Transmission is on its way. We aren't all there yet, but we will be.

Question: When you ascribe a value to the FTRs for the purposes of a PBR, for example, are you doing it on a forecast value or what actually turns out to be the value at the time?

Response: You would have to do it on an expected value. My guess is that it would be the ISO as the RTO doing the benchmark because you don't really want the transmission owner to say, "I can name that tune in 20 notes," and if you name it in 19, you receive all kinds of money. You do want an expected value set. That will probably be set through historical information and could lend itself to some sort of benchmarking. I see that as one of the ways to get to meaningful PBR.

Question: Do you see FTRs as completely capturing the value of a transmission expansion? We were faced with a generator hooking onto the grid, expanding transfer capability on the grid and at the same time, the transmission owner included a reliability upgrade in its five-year plan. With the generator coming on, it basically deferred the need for the transmission facility for 5-10 years. The transmission owner said it should be compensated for the time value of money, basically deferring that transmission investment.

Response: Once you have markets, the integrated resource planning process does not work very well because anything you have fought through as a regulated investment in transmission may be rendered obsolete by an investor on Wall Street. The last resort piece that is where I think your transmission investment would come in is a very small part of the solution. It really is reliability upgrades, stability upgrades, not economic upgrades, because the expectation is that once you have LMP, merchant companies will capture the transmission value and generators will capture the high spot prices. You will wind up stranding those transmission investments and that will be on the backs of consumers rather than the at-risk dollars of Wall Street, which is probably a better place for the at-risk dollars to be.

Question: Are you saying that the value proposition is in terms of the FTRs for a transmission owner?

Response: The value is through FTRs as one form. But I want to expand the definition of FTRs as relieving the existing congestion. When you relieve the congestion, the FTRs are gone and their value is zero. The payment of money you have received is either from the load in the high-priced area that wants to access lower-cost generation or the lower-cost generation that wants to get more value and has accessed the high-priced load. I look at those as FTRs sold forward – the congestion relief sold forward. You hold them until the next person using the spot market comes through and creates congestion and you are held harmless against that new congestion.

Question: Do you agree that as soon as you build it, it is gone?

Response: It may be gone. That is why we see that most of the merchant transmission is now DC because the value is a little more controllable. We are working on how to capture the AC value.

Question: You premise liberating the grid owner on when the functions requiring independence were with the RTO. When is it that the functions rest squarely with the RTO? When can you liberate the grid owner without running afoul of a whole set of other problems?

Response: When things are with an entity that doesn't own assets that can compete, and the competing assets to solve congestion are transmission, generation and demand side.

Question: Is there any problem with a transmission expansion planning process that involves multiple competitors in transmission?

Response: No. I think that is how the planning process works best. PJM's experience is that the RTO collects the competitive, market-driven solutions and sees if there is any de minimum reliability upgrades needed to hold the grid together.

Speaker Four

There are many proposals about incentivizing transmission build and operation and they don't fit together very well. We need to be careful to pick a coherent set of proposals that have some simplicity. They need to be direct and they need to be tried and tested. It is an interesting philosophical question whether transmission competes with generation and demand. More fundamentally, we know that markets will not work without adequate transport. As with any commodity, you have to be able to ship from numerous suppliers to the consumers to allow proper competition to prevail.

My experience is predominantly in the UK wholesale market where real prices to customers have come down by 30 percent in the last decade. I believe deregulation is tremendous for the customer. But the markets will have their credibility damaged if we haven't got enough transmission. I don't think we actually know whether we do. In some situations there are some market power tests that can be applied, but I have not seen anything significant that says we have enough transmission to start.

We have had success in introducing markets in generation; why shouldn't that work for transmission? There is an easy measure of whether you had enough generation before you introduced the market. You could measure whether in aggregate you had as much or more generation than demand. If you thought you did, then putting in markets appears to be an excellent thing. The slight difference with transmission is that you need enough of it to make the markets work. I think it is more difficult to measure whether you have enough of it before you introduce the market.

The myth is that the market will make it right if we haven't got enough. But if we haven't got enough transmission when we introduce the market, the market will not work; there will be blatant market abuse. There will be a lack of competitive intensity; prices will go up; the markets will lose credibility and deregulation will stop. This is a game of high risks and there are some worrying indications about whether there is enough transmission.

Historically, the US system is fragmented and was designed for a completely different purpose. Wherever a market has been introduced around the world, a dramatic step upwards in transmission capability from that needed for vertical integration has been required. For five years in the UK there were problems with market abuse, market power behind constraints and lack of competitive intent in the wholesale markets. It took five years to ramp up the transmission capability to a level where regulatory intervention was not required to control those market abuse opportunities due to lack of transport.

Remember, also that there is a mixed technology generation sector with strung-out incremental cost production, from nuclear to expensive oil. Competitive intensity at the margin at any time will be pretty thin. If the generators compete for monopoly rent behind congestion, then you will ratchet up the level of congestion payments and also damage the competitive intent in the wholesale market – potentially a much larger problem.

If you introduce LMP and haven't got enough transport, then you need price caps. By putting on caps, you will not see the messages we rely on to make the LMP market work. I believe in LMP markets, but I believe in operating them where you have enough transmission in the first place. Remunerating investments with LMPs and FTRs is a sensible way of clearing the generation market and I think the FTRs as hedges will be required for generation and demand. The issue is whether they will lead to enough transmission being built. There are issues with relying on FTRs to incent building of transmission and indeed, effectively running it in the short term. The regulators would have to be willing to let the market give strong signals for building and letting the signals go into the retail base. You have to rely on regulation and be willing to let incumbents withhold transmission to make this work. There is no sign anywhere in the world of forward LMPs that will run anything like that. LMP fourth markets virtually do not exist.

Does this mean that transmission should not be built? An obvious example is in Central East where the FTRs clearly will not fund an investment, or TCCs in New York, and yet the economic case for it is overwhelming. There are free rider problems. There is lumpiness. And to be honest, some people do not want transmission built. There is a lot of bureaucracy in a planning process that is already fragmented and needs to be integrated.

We should be more direct, to encourage the formation of strong transmission companies. The double jeopardy is that LMP just raises the opportunity for market abuse in vertically integrated structures. If FERC is going to push LMP and encourage disaggregation of the industry, we are heading for market failure and the end of deregulation and that is not good for the customer.

Merchant transmission has its place, but building it takes a long time. If we are already five years behind in building the grid that we need, merchant will take another five years to receive planning permissions and get through the obfuscation of project opponents. So we need to streamline the consent process and promote active management of the grid, because congestion is an absolute poison to the wholesale market and will ultimately lead to its credibility being ruined. Let the grid be integrated and let the transmission professionals get on with their job. Let us deploy technology and get a system that enables the markets to work properly. By all means, challenge transmission owners with prudency risk and ensure that where ITCs and TOs cause congestion or losses or anything else by the inadequacies of the transmission system, it should hit their bottom line. This solution may not be intellectually elegant but it has been tried and tested successfully elsewhere. Let's get out of the conference room. The transmission towers are calling.

Discussion

Comment: A clarifying point about when congestion occurs, PJM has a bid cap to mitigate market power where the market is not thick enough. Usually that is where a single generator can solve an off-cost problem. Where there is enough thickness – for example, in the east, west and central transfers in PJM – congestion is solved through the market-based bids. The expectation is that with the new entries, demand bidding and transmission, there are enough players that the cost-based bids go away eventually. But these are price caps on the bids, not price caps on the payments.

Question: The US is woefully short on transmission at the moment. How would we know when it is not?

Response: Where you need to put bid caps in pace or have regulatory intervention, you haven't got enough transmission. I have experience in watching regulators trying to cap market power because of lack of transmission and it does not allow the market to function as it should. After five years the UK is in a position where generators can bid what they like and the transmission company takes the risk of being unable to control those monopoly rents. That has led to a reduction of congestion from $500 million a year at its peak to $30 million a year. That is a pretty good result for the customer.

Question: Is there something a little more numerical than "pretty good?"

Response: Maybe some of the market power tests could be applied to areas as large as the eastern interconnects, to look at the ability for generators to extract monopoly rent in a consistent way. This is useful academic work.

Response: There is a bit of a fallacy to the question, as if there is a measure or a group of metrics that could tell us what is adequate. In reality we cannot remove all congestion in every direction. I believe that the customer determines if there is enough transmission. Some people at FERC have said, "You have to determine where the market is going." But I am the controller, not the enabler. The customer tells me by request. Transmission is not a stable capacity. It's not a number. As load grows and comes down, as generation is shut down in old places and built in new ones, we continuously address the issue of need. It cannot be done in one day, but requires a long time.

Comment: The three ways to make more transmission available are to build more; to put on a generator to run counterflow – making available more transmission room; and removing demand from the system, which is the demand side equivalent of counterflow. We don't know the value when we don't always have the demand side bidding against supply, or the transmission owner bidding against both. LMP makes sure we have all the pieces together.

Question: In the US generators effectively have less geographic reach at a time when we look to them to serve broader markets. When the market opened, the UK did not actually construct a lot of long-length overhead transmission. Wasn't it mostly operational changes, devices and other reforms?

Response: There is one significant new right of way that we have tried to build for nine years. Without any new ROW we have driven up the capabilities of the transmission system by 22 percent over that period.

Question: There is no doubt we need significantly more effective transmission capacity, either by adding it, improving controllability or by more demand response. Should one centralized company – the blunt instrument approach – do it or should it be more interactive and market-driven?

Response: When the system is inadequate to begin with and you cannot install generation of any size anywhere without building transmission, you cannot apply high technology. Different areas of the country also face different realities.

Response: There are technologies that can take an existing right of way, put up new conductors and drive up the capabilities of that ROW by 30 percent. You need a driver to innovate; now there isn't management focus on getting the job done.

Question: In the world in which I live there is huge technological change. Demand grows in ways that I can't possibly anticipate. And we are going to put in place some transmission lines that will last almost indefinitely, certainly 40 or 50 years. Then we are going to ask the marketplace to tell us exactly how to evaluate and do that. How do we solve the transmission problem when we have non-linear systems and we are trying to do dynamics over long periods of time and we have other uncertainties?

Response: We know how to do a vertically integrated regulated system with monopolies and that that path does not work perfectly. Another path is to give people the signals and incentives so the risk will be allocated in a different way. We also worry about how the two paths overlap – regulatory backstop is an example. It is never easy to make the decisions, but the sense is that we will do better if people are spending their own money in making the decisions and trying to get what benefits we can give them. I am not claiming that relying on markets solves all our problems.

Comment: A useful inter-RTO example of a huge spread is New York to PJM. The LMPs are very clear and there are several transmission projects that I think actually may get done in time if we can overcome the regulatory obstacles. Another example is the generation pocket in southeastern Massachusetts and Rhode Island to the load pocket in southwestern Connecticut. If NEPOOL had LMPs, the energy spread might be $7-8 per MWh and if it had an ICAP market, there would probably be a good spread, too. A third example is a Boston-style market with lots of distribution and quasi-transmission investments that have to be made. In that case, it is clear that the ISO can help the regulated utility there identify its responsibility. Speaking as a developer and an investor, I am sufficiently attracted to two out of the three that I want to pursue them.

Response: Sometimes very good projects will not get done. The incumbent utilities need to be able to make the economic case under regulatory return for such projects. There is tension between the incumbent and the merchant in the second example. We have to find a way to make those work together.

Response: Very good projects do get done on a merchant basis, or by whoever can get the property rights. In the third example, if the incumbent utility did the upgrade on its own nickel, it would receive nothing. Therefore, it would be in its interest not to do it. To the degree that it is a buying company and can access a lower-priced market, then the benefits would be through its buyer, but not through its transmission company. It is in the property rights that if you pay for something you get a benefit in return.

Question: What are some of the regulatory obstacles?

Response: I do not think they are onerous, but they do take a long time. In an urban market like New York City, if there are eight projects and only three positions on a bus bar, you have a difficult regulatory issue to resolve through adjudication.

Question: Are you suggesting that FTRs are useful for smaller-scale, modular projects but may be unworkable for incenting investing in large-scale lumpy projects? What are the viable means to risk investing in them? Do you see investments in long-term power contracts as a way for investors to make money on their transmission?

Response: If the increments are small, by definition they do not have a material effect on the marketplace and will not change prices dramatically. They will increase the capacity a little by the amount that they have created and you can capture the associated benefits. Many people say that there is a big difference in price before and after the fact, which I suspect is actually rare for really big projects. One way to attract investment is to sell FTRs forward. Once you get enough people to sign up in advance, then you make the investment. Now what about the big ones that come back and drop their price to zero and you can't attract enough people to sign long-term contracts because there are free rider effects? One path to take is the regulatory backstop mode. Another is that you don't have to have a full IRP that includes every tiny thing that could happen because those are in the modular category. You only evaluate are other large, lumpy alternatives and that simplifies the problem a lot. You could also put in a large, lumpy 500 MW or 1000 MW capacity line and say that it is a 200 MW line because then it looks modular and therefore the price differential will not change. In other words, you constrain the access to the new link in order to keep the prices up so that you can collect enough money to pay for it. For incremental things that are merchant, you might allow them to withhold the capacity so that they don't have to build a 1000 MW line the first day, even though they do – but they just withhold some of that capacity.

Question: For a line that is capped at 200 from a financial standpoint, but is built ultimately to carry 400 or 1000, is it physically dispatched as if it is 200 or is it available to the system operator as if it had its full carrying capacity?

Response: We don't dispatch lines with dispatched systems. If we know the line's capacity then we have an obligation to tell you and the owner describes that. Most lines in the US are not run to terminal capacity, although sometimes they reach it because of contingency.

Comment: It is against the rules today for existing regulated investments. I would say it should be against the rules prospectively for the regulated investments. For merchant investments that are not in rate base and people take their own risk, mechanically there is no reason why you could not artificially lower the capacity. It is a judgmental number anyhow. You cannot change the impedance. So that will have the impact that will change system flows all around the network. But you could dispatch the system as though that line were 200 MW as opposed to 1000 MW.

Response: It goes back to the generator analogy. The generator says, "Here is what you get at this price and here is what you get at that price." For the merchant transmission, there is no reason that a big construct could not say the same. That works well in my model of system operations. The important point is that the things paid for by consumers need to be allocated fully and the benefits to those consumers need to be available. On a merchant basis, a merchant generator can do it, so why shouldn't a merchant transmission owner?

Response: Everything depends on everything else in the AC network. No line creates capacity; a single line, in fact, would have zero capacity. When you run something in your system that limits what somebody else has to do, then you have a significant conflict because the capacity and earning ability of the line depend on the capacity of everything else. You cannot limit yourself in the AC network. You'll have nothing but lawsuits.

Response: I think there is a way to do this. I am talking about a system that is under the feasibility rule and feasibility test. When you put these lines in, it creates new FTRs. If it eliminates some others because you call it a 200 MW line, then somebody else has to buy counterflow in order to compensate for the FTRs that are eliminated, and so the existing rightholders are all protected. You can certainly operate the system that way.

Response: When the market rules are constructed correctly people who have a product to sell want to sell it. If I bid in all of my transfer capacity or my transfer capability at varying price levels, I am not withholding; I am just pricing it.

Comment: Our projects in Australia do the same thing that a generator does. Both market network service providers, as entrepreneurial interconnectors are called, and generators withhold. They choose to bid some amount some days and a different amount on others. That is how markets work.

Comment: The FERC Neptune order is somewhat revealing because FERC allowed Neptune to auction off all of what it calls TSRs – transmission service rights – which is its own invention because that is what you call things between two RTOs. They are the same as FTRs but they are physical because it is DC and it is financial because they are long term. FERC ordered Neptune to sell all its TSRs so that there will be no withholding. From the standpoint of the merchant transmission entity, I guess the evidence of non-withholding is the sale of TSRs. By the rules that FERC is trying to set up for merchant DC transmission, you cannot withhold in a legal operational sense, but perhaps you can withhold through your activity in the marketplace. But as a transmission owner we are precluded from participating as a generator in the marketplace.

Comment: To get new transmission investment, is the incentive issuing new FTRs or is it the entire revenue stream? Even with small, incremental investments, every increase in transmission has the potential to reduce congestion a little. As this occurs, the spread between the LBMP narrows so the congestion rents get smaller. Adding new FTRs also decreases the value of the existing ones. Can a case be made to get transmission built when it is paid for by FTRs if there is a chance those congestion costs will disappear and therefore the revenue from the FTRs will disappear?

Response: Things will change tomorrow. Somebody will make another investment and what you thought was valuable might turn out not to be. That is a business risk. The argument with markets is that the people who ought to evaluate the business risk are the people who put up the money to make the decision to make the investment. The risk does not go away.

Question: If there are access fees for using the system, and FTRs for hedging or effective congestion costs built into LMP, are the fees that are paid going to the extant transmission system or the transmission components that are there, plus those that are built by regulated companies? Do no access fees go to the merchant that also owns a piece of the system?

Response: None of the access fees go to the merchant.

Comment: Look at it as a follow-the-money question and sort out what is embedded, existing and incremental. Once you do so, it is an accounting problem. To the extent that the embedded cost is paid off through the access fees, the FTRs from that go to the consumers who are paying it. Someone who has made grid capability available receives the FTRs for that part. A merchant investment in transmission gets the FTRs for that part. Your entitlement to the FTR or its revenue stream goes with the money that you put up to make it available.

Comment: By the end of summer 2002 Transenergie's projects in the US and Australia will total a quarter billion dollars US in investment size; 171 miles in total distance; 700-plus MW of total transmission capacity which if the math is right is probably 43 gigawatt-miles, assuming it is just the product of the line rating and the distance. All of this is underground. The 171 miles is all negotiated ROW, without any eminent domain exercise. It was developed on an arm's length basis by landowners who were entitled to say no. From project kickoff to finish they have all been three years maximum. Perhaps future debate needs to reflect such facts. A comment about the adequacy of FTR revenues to fund such projects is that if you take the risk to build them and the congestion rents disappear you have nothing. The same applies to anyone building a peaking plant in a market that has an installed capacity obligation and that one plant could take the capacity price from $5-6 a kilowatt-month to zero. The revenues in markets with these risks are wild and volatile. If you decided to use market power within the generation sector as a test for transmission adequacy, would the existing transmission grid in, say, the Boston area, be considered closer to adequate if in fact all the generating stations in Boston had been sold to separate generating companies rather than as a fleet to a single buyer initially? If the answer is yes, because you would have more competition, does that introduce the notion of a structural remedy to a market power problem that does not involve building new transmission?

Response: A lively merchant transmission sector is well worth having, particularly between markets. But a lot of the solutions, if they are to be done quickly, will be on existing ROW and on existing AC systems, which have issues associated with the ability to withhold capability on the systems and issues about who owns existing ROW. We could be heading for a position where we then throw existing ROW to anybody who fancies pitching for them. Then nothing will get built. We have to use what we have and upgrade it as quickly as we can.

Question: How should the unmeasured impacts on bilateral prices be accounted for when you are talking about two cents? It is about four times the cost of the existing transmission system when measured on a per kWh basis.

Response: If you look at single spot prices for New England with no locational differences, your overall market is so inefficient that you do not have a good measure of a spot value. First, you do not have the locational values. You have spot prices that are too high overall. You have congestion costs that are side payments somehow. You may want to try again when you have LMP because then your bilaterals will be on an equal footing with your spot market.

Comment: My friends live on Long Island with LMP pricing. I have difficulty explaining to them why their high prices do not go down. They compare it with the old days when the utilities had to plan sufficient transmission generation versus the new markets. They see a lifestyle change that LMP has not addressed.

Comment: This is about whether the market will work, and whether anyone who wants to spend money on infrastructure will have any incentive to do so. If we are solving a $10 million problem with a $250 million investment, we have done the wrong thing. I do not want to trivialize either side of the debate, but we need to find that proper level.

Question: How can I decide today to accept an FTR – whether it is positive or negative -- for 40 years in a dynamic electric system where demand could shift dramatically over the course of those decades?

Response: If you invest in a line, then FTRs with a 20-year horizon are awarded. You can then sell them in the market that can use transmission or sell them to third parties. You can sell in advance or take the business risk and sell them later. That is your choice. You decide before you invest. You could choose to make the investment and not take the FTRs as long as zero was simultaneously feasible. Now if you were eliminating some because of the investment, you would have to provide counterflow as part of the requirement going along with your investment. Like the existing system for long-term FTRs, if you have a long-term power contract with the obligations, then it is a perfect hedge and it can go for as long as the contract and as long as the FTRs. If we award you the investor the FTRs that you were going to sell for 20 years and 10 years later you decide to take your line down, we need a decision rule for what happens in that situation. And the question is who should make the business decision to invest: you as investor, or the RTO that then sends you the bill?

Comment: It would help if there were shorter-term depreciation for merchant transmission and a longer schedule for conventional regulated transmission. It might attract investors to opportunities that appear to have the most value to the merchant marketplace.

Response: There are three kinds of depreciation; one being what the IRS allows and we're not talking about that. The second is what regulators allow. It doesn't arise for merchant transmission because it is unregulated. The third is the economic depreciation used in setting the prices that you get for the FTRs. For merchant investment, you decide their duration and what you will sell them for.

Comment: In long time frames, I am not sure how we would reconfigure the FTRs.

Response: PJM is already doing annual FTRs with monthly reconfiguration. You have to get the time frames so the rights are matched when you do reconfiguration auctions. For long-term FTRs, you might reserve some, reconfigure some and constantly hold auctions for 20-year rights that you reconfigure in the next cycle, say six months later. You would then have a different set because you sold the old ones and bought new ones. Another way to think about a situation where your new transmission line causes you to have to buy back some rights from someone else, is that you assume the obligation to provide counterflow rights. The other person does not sell back the rights, but keeps them for 20 or 40 years. Already, people are providing counterflow rights in the auctions. The surety issue is dealt with by a requirement to put up a bond.

Question: My sense is that if you are withholding transmission capacity, you are extracting the full economic value of that asset, but customers more than likely will pay more at the end of the day. Regulators will not want this to happen.

Response: The logic of the competitive market is that new entrants have to be able to capture benefits by entry. If you do not let them capture that benefit or you do not have something like a regulated mechanism in order to get an investment made, then the merchant does not make the investment. The benefit to the customer is that they enter, and it is better to have 200 MW than none, even though it might have been cheaper to build 500 MW. So 500 MW are built and a high price is put on it. They just bid it in at these prices and you are better off if they do.

Question: I am confused by your premise that customers should benefit from something they did not pay for. If the customers have paid for the line, there is no reason why it cannot be made available. It is done now through the component ratings. Is it that the customer has paid for the transmission service rights or if they haven't paid for anything, they ought to get something?

Response: Under rate-based assets, ratepayers will pay the cost of service over the 40 years. If I am a state regulator and I see that there is a potential for higher prices because of merchant transmission withholding, I don't want anything to do with it.

Question: If you have an IPP, what is the state's mandate for that IPP to have to bid into a marketplace? With the RTOs I know, if you are not a capacity resource, you do not have to put your power in the market.

Comment: The bottom line is that customers are going to pay, whether it is a merchant transmission owner or whether it is regulated.

Response: On average they will pay. But the theory is that the risks are distributed differently between the two activities. If it turns out to be really valuable, the customers will pay more because the value will be captured by the investor and if less valuable, the customers pay less because the investor takes the hit.

Comment: Another part of this equation is the real possibility in cost of service rates of stranded costs that customers will pay.

Question: Let me rephrase. Did the decision to sell all of Boston Edison's Boston-area generation as a fleet increase the need for new physical transmission assets in the Boston-area region?

Response: We are in a paradigm that says if you are the only generator that can solve a congestion problem, we immediately either need more transmission or we have market power. It is not always the case that there are not enough generators to solve congestion, in which case you do not have a market power problem. If you do have market power or a very large concentration, if you sell that to another entity do you solve your market power problem? No. If you have one generator that can solve the problem and you sell it to somebody else, it is still that one generator that can solve the problem. You need more competition among that particular generator which comes either through getting a demand response in that area, building more generation in the area or getting more transmission to open up the competitive access.

Question: If five generators can solve the problem, do you need more transmission if those stations are owned by one entity than if they were owned by different entities?

Response. Yes.

Comment: If it takes collusion across more than one in order to extract the monopoly power, then splitting them up solves the problem and you do not need the transmission. You have a problem if it does not take collusion across more than one of the five plants. Again, if you have LMP in place, you get exactly the same signals in terms of LMP as to how much transmission you need. You have a problem about the pricing signals sent by the regulated transmission, but that is another issue. Rolling in transmission pricing mutes a lot of the incentives for generation location and the other things that will be important with LMP.

Comment: Is the self-defeating aspect of merchant transmission any worse than merchant generation? For example, we do not assume that a peaking plant is bidding in at zero in setting LMP. But with a merchant transmission line, unless something is done, we essentially assume that the price of its use is zero.

Response: In Australia, since they don't withhold, what they are doing is actually bidding. They are not bidding zero for the use of the line, whereas in the US, the rules act as though you are bidding zero. I suggest that this should not be the case for merchant lines.

Response: A high LMP somewhere will either encourage you to build a line into or site a generator at that high LMP. Your risk as a generator is that another generator might come in, or as a transmission owner, the risk is that a generator or another line might come in.

Comment: I agree that in the US merchant transmission that can meet the same criteria should be given the same bidding capacity as merchant generation.