

**Harvard Electricity Policy Group
Twenty-Seventh Plenary Session**

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RAPPORTEUR'S SUMMARY*

Session One: Market Power and Market Makers

The Enron bankruptcy and the putative merger with Dynegy raised new questions about the definition and nature of market power. How do trading activities interact with hard assets and real markets to create, extend, or limit market power? Can brokers and traders who deal only with derivative contracts exercise market power in the electricity market? Can traders exercise market power in the trading market? It is well known that trading positions can leverage market power in physical power markets, and thus market monitoring must consider the effect of trading in enhancing profits from withholding real production. But how does the analysis extend to address the role of pure trading activities that are divorced from control of physical assets? What should interest regulators who face the prospect of a merger of two large traders?

Speaker One

There are three different cases in which market power might be exercised in different contexts. The first case is in the physical spot markets that are used to exercise power in the spot cash market. But it's also well known that one can use derivatives markets to accomplish some leverage and get additional value from that control. The second is the notion in a derivative market between an illiquid and a liquid market. Liquidity simply refers to

the immediacy with which you can undertake a contract. For example, if you want to sell your house within the next 30 minutes that's an illiquid contract because there aren't very many offers coming in; on the other hand, if you want to sell 100 shares of IBM stock, you can do that in under a second. The distinction between immediacy and lack of immediacy and liquidity/illiquidity is an important one. In an illiquid market, there's good empirical evidence that corners and squeezes can be used within the contract market to cause

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forward prices to affect spot prices. In liquid markets, although in concept you can do the same, it becomes very risky and expensive to try to execute, and you can end up essentially getting arbitrated and lose quite a bit of money. The method of manipulating a physical spot market would be withholding the physical supply from the market. The method in an illiquid market would be to take an open position that requires more delivery than is available. And in a liquid market, any effect you might accomplish would be fairly transitory with little benefits. In the physical market, prevention mechanisms would be just limits on market share. Typically, in illiquid markets, in exchange derivative markets, you'll see limitations on open positions expressed in a percent of physical market. The third concept is the importance of having a well-functioning contract market. If you think about one of the dominant electricity requirements as being a swap of fixed for variable price, you'd like to have an efficient market that provides you with prices at each point in time. The demand for each contract then becomes an evolutionary supply/demand for the contract itself, with order flow on the buy side and the sell side not necessarily directly related to the cash price.

The essential features of the derivative market really don't have physical market analogs. For example, if I own a power plant or an oil refinery, I don't mark the value of that to the market value every day, but if I have a derivative I do.

The value of a swap can change in direction up or down. Margin requirements are common in derivative markets. Another difference between physical and derivative markets is the contract volume. Although we often measure market share in the percentage of physical buying and selling, in a derivative market like agriculture you'll often see contract volumes that are 5-30 times greater than the underlying physical,

and that creates an efficient market in terms of revealing forward prices. Another important concept in derivative markets is replication and no arbitrage. Revocation means that I can construct arbitrarily one derivative from another derivative in a way that replicates the financial outcomes to me. So one contract can be turned into another. A forward contract, for example, can be thought of as a long call and a short put option.

Generally, the concept of no arbitrage is for efficient pricing, meaning there's a triangular equality that can exist between different derivatives, and if those prices get out of synchronization, I can make an arbitrage profit.

A well-functioning derivative market includes high level of liquidity. Order flows and executive are critical to achieving liquidity, as are price transparency, immediate public distribution of settlement prices, credit checking and margining, because as we write derivative contracts that have high leverage ratios, of course we can have credit that starts exceeding the exposure you'd like to a particular counter party.

In terms of the flow of orders in a well-functioning derivative market, we'd like to have both traders who demand immediacy and those who supply immediacy. Typically, traders looking to hedge an existing position, whether they're a producer or consumer, or whether they're simply balancing a book of trades, want to place an order and have it executed immediately, whereas market makers supply immediacy in the sense of balancing a flow of orders to buy to sell. Immediacy that has a value is often expressed as the bid aspect. Finally, a well-functioning derivative market will typically be executing position limits to avoid the kind of problems with squeezes and corners that can occur. There are some essential activities of derivative trading related to keeping value at risk low that to

the uninitiated might appear to be manipulation.

Speaker Two

There are things that have happened at PJM that reflect what we could call market power based on trading activity, as well as interaction between trading and ownership of assets. In PJM, forward markets are traded both in energy capacity as well as the RMTR market. The traditional definition of market power obviously gets a little bit more difficult when one is talking about forward markets. The reference for market power is obviously the competitive price. It's easier to say what the competitive price is than it is to identify it exactly. But at least identifying it in the real time spot market is doable. It's a function of marginal cost, opportunity cost, optionality, risk and scarcity. Competitive price in the forward market is tougher to define. It's basically when the forward price reflects the expected spot and reflects the expected underlying fundamentals. Clearly, the question of what a competitive price is in a spot market is testable. I would say the question of what the competitive price is in a forward market is probably not testable. Maybe after the fact, one can look at convergence, but it's pretty tough to test at real time.

I'll give a few examples of what I regard as exercising market power in PJM using trading, and using combinations of trading in assets. All are public and have been the subject of, or are currently the subject of, investigations of one kind or another. What we saw in our daily capacity credit markets earlier in 2001 was the use of trading to enhance and/or create a pivotable position in the real time market and the real daily spot market, and then the use of that pivotable position to exercise market power. I believe market power was, in fact exercised in the daily capacity market, and the results of that market power were also levered into the

bilateral short and longer-term markets. Price expectations and expectations of scarcity, whether real or created, were in the real time spot market carried over to the bilateral forward markets. Clearly, a physical position played a role in these events, but was not necessary in what could have been carried out purely as a trading strategy. Basically what happened is that demand jumped up on January 1, 2001 as a result of the way in which it is set at PJM, a result of a forecast of load serving energies, load obligations. One possible source of that increase in supply was a trading strategy, that is, buying bilaterally in order to both create and enhance what clearly is this pivotal position. The graph of the price in the daily markets goes at its maximum for about three or four months. The first spike in the daily capacity markets occurred in 2000 and was, in fact, a result of underlying market fundamentals. The second spike in January 2001 was a result of market power. Ultimately, when that resolved, prices returned to more competitive levels. After PJM introduced increment and decrement bids in the day-ahead market, along with the monthly FTR auction, the pattern of behavior basically was a reflection of entities, traders, on a purely financial basis finding radial transmission lines -- that is, one end basically dumping to load, dumping to a distribution system, which were typically close to being congested in both real time and day ahead.

The strategy then became to take an inc on one end and a dec on the on the radial end, and to congest a line, first having purchased an FTR in monthly auction. An FTR's value is a function of congestion. On a radial line, you can create congestion in the day-ahead market, which is where FTR value is created, by inc'ing and dec'ing a cross-out line with virtually no risk. The fact that it's on a radial portion of the line is that the impact of the inc's and dec's is very high; that is, the distribution factors are very high. You don't have to

put in a load of 100 MW to get an impacted five. It's virtually one for one.

To illustrate, we have Bus A and Bus B and a 50 MW flow, typically. I buy a 40 MW FTR; I put in an inc of 10 MW and a dec of 10 MW. The flow is now 60 MW. The line is congested and in the split in the day-ahead market across the busses, Bus B is now higher. In real time, there is no congestion because the congestion didn't reflect the underlying flows. It affected purely this financial transaction. There's no gain on the inc. value. The dec value is actually minus \$250. The FTR value is increased as a result of the strategy by a thousand, and the net increase is \$750. Another example of a potential situation having to do with FTRs and with the relationship between transmission outage reporting in PJM and the timing of the FTR market is that before late 2001, the reporting requirement was simply that it be three business days prior to the outage. Because that occurred well after the FTR auction for the month, it created an incentive, although there's no evidence of this, to share information in violation of FERC regulations between a transmission entity and a generating or marketing entity about the nature and timing of an outage. In fact, it's not actually necessary to do anything illegal and it's certainly possible that those who used to work for the transmission company are aware of the typical timing of these outages. There was asymmetric access to information and incentives created to gain that information.

In the pure, over-the-counter bilateral energy market at PJM, I think we've seen that liquidity has increased fairly significantly since 1998. The PJM hub is relatively liquid compared to the markets to the north. PJM is somewhat less liquid than Intersynergy and Interenergy, and comparable to other hubs to the west.

Positive impacts are arbitrage in real time between short-term and long-term markets, fair valuation FTRs based on

expected congestion as one would hope when the forward market is working well, and trading has permitted those in PJM to leverage asset-based market power, and provided the opportunities to hedge and transfer risk, which is critical to markets working. The pure, over-the-counter energy market is working better than it did.

In conclusion, the straight over-the-counter energy market at PJM is becoming much more efficient. Nonetheless, the existence of trading creates opportunities to exercise market power and we have to be aware of that.

Question: How do you define market power?

Response: The simplest definition is for the real time spot market, which means you're raising the price above the competitive level. The competitive level is defined by the marginal cost of the last unit to operate where it's understood that marginal cost is more complicated than the marginal running rate. It includes opportunity costs and optionality, particularly for units that have limited run times. It includes risk.

Question: It is definitely not tied to withholding?

Response: One mechanism creating market power is withholding. The problem with that is there's no good definition of the right level of duration in an energy market. Certainly it's an issue. It's of much less concern than if the conditions that underlie it mean that it's generally reproducible when those conditions recur.

Question: How do you measure what's scarcity versus what's market power?

Response: There are certain circumstances, both locally and in aggregate, where the demand for energy pushes up against available supply. It

would be easier to define scarcity if you were in an island and didn't have imports. In PJM, one function of higher prices in the aggregate market is to induce imports. If you're going to define scarcity, you have to have a reasonably good sense of what the elasticity of supply of imports looks like, as well as the physical capabilities of generators inside. It's certainly not easy. In the summer of 1999, we made an attempt. Instead of saying, "Look, you exercise market power; you owe us this amount of money," the intent going forward is to make sure that the market design limits the ability to exercise market power in such conditions. We erred on the side of not intervening in the market when demand was high because high prices serve a needed and positive signaling function.

Question: Define a corner and a squeeze.

Response: A corner is simply controlling a sufficiently large percentage of the market that you track the prices up and down, by either withholding or flooding the market. Essentially, you would be a price setter and a price maker. A squeeze is a special situation when you're controlling more contracts than there is physical delivery capability. Anyone who is short a delivery contract gets squeezed.

Speaker Three

Fundamentally, is market power being exercised and am I impacted differently, depending on the nature of my approach to buying power? The distinction, I think, is relatively insignificant. To the extent that market power being exercised, it's going to manifest itself both in the short term and spot markets, as well as in the forward price of energy. If it's vertical market power that's being exercised, and there's uncertainty around physical delivery of power to a particular hub, that's going to manifest itself with some type of rent that's built into the forward price of energy, just as it's going to

manifest itself in the short term or spot price of energy. As a consumer, you're negatively impacted regardless of your approach to buying. You're going to see sharper spikes where in fact the market power is being exercised, perhaps along the lines of what PJM has demonstrated. But it's still going to get built into the price that you're paying as a hedging consumer if you're more assertively moving into the power markets, or to the forward markets.

When Enron Online was still in its relative infancy, you could actually look at the bid/ask spreads, depending on the market that Enron and Enron Online were making, and draw some conclusions about the efficiency of a given market and the degrees of liquidity and transparency in any given market. The more efficient the market, obviously, the lower the bid/ask spreads. For example, in gas markets, one would see the bid/ask spreads oftentimes in fractions of a penny, whereas in power markets like the Midwest and the Southeast, one saw good bid/ask spreads up in the 50, 70, 80 cent range -- a multiple of 100 or 200 of the kinds of bid/ask spreads in the natural gas arena. Within the power arena, one would see significant differences as well -- nothing, no bid/ask spreads as low as in gas markets, but PJM being in the 10-15 cent range versus the Midwest and Southeast markets. Much of this was a function of vertical market power being exercised in the power markets. One of the things that Enron tried to convey to policymakers -- which sometimes is lost in the academic discussion around market power -- is that there is a real consumer harm that comes from that market power being exercised. One of the best ways that we were able to demonstrate it was actually around the bid/ask spreads because that was getting translated into the cost of power that companies were buying and, ultimately, into the cost of power that consumers were seeing. There was a real world impact to the market power being

exercised. Obviously, that's been an issue in California. Whether we ever sort out if and how market power was being exercised, there clearly was an impact on consumers.

One issue is the role of another Enron in the way that Enron traded in the energy marketplace where it was a relative asset-free company that was making markets in different energy commodities at many different hubs. What were the market power issues that were implicated by the potential merger of Dynegy and Enron – two companies with a significant trading presence in the market? It's very difficult to correlate exactly what's happened in the marketplace since the demise of Enron since there have been other phenomena such as credit constraints with many companies that have begun to enter the picture in a significant way, and that have had an impact on the amount of liquidity in many of the energy markets. I've heard consistently that there's less liquidity at a lot of the trading hubs and less transparency as well. One thing that Enron/Enron Online contributed by showing two-way prices at virtually every trading hub in natural gas and electricity was a significant degree of transparency that has not been completely replaced by other entities in the marketplace. Along with less liquidity at these trading hubs, not surprisingly the result has been wider bid/ask spreads that have a real-world impact ultimately on consumers.

I'm not sure how much of that to attribute to Enron's demise, and how much to the fact that you've had other entities that have been squeezed from a credit perspective that obviously have reduced their trading activities generally. There's an argument to be made that the demise of the role that Enron/Enron Online played has had a negative impact, as you've had this market making function disappear from the scene. It's not necessarily clear who will fill that role. People who are expecting UBS to fill that role may well be disappointed. The

way banks run their trading operations, the daily value-at-risk tolerance is much different from the kind of VAR tolerance that existed at Enron. The ability to go in and make markets may well be severely hampered in a UBS context.

Would Dynegy's acquisition of Enron have mattered from a market power perspective? There was a perception that it was a significant issue because one company had a 20-25 percent market and the other with 10-12 percent. Twenty-five plus 10 doesn't necessarily equal 35. Even if it did, it's not clear that the market power implications were all that significant. A lot of that has to do with the nature of the market-making role that Enron was playing, where it was invariably showing two-way prices with every product at every trading hub. It negated any incentive to withhold from the marketplace, which one might see with more of a horizontal market power situation where someone may well be withholding generation from the marketplace to drive the price up.

Where you're showing two-way prices and you truly are making your money on volume, and also being able to somewhat accurately predict the way that markets are going to move at any particular trading hub, the incentive to do some of the things that have been traditionally associated with generation market power are not there.

The other question is what are the best defenses against market power being exercised, whether it's of a vertical or horizontal nature. At the macro level, the answer is efficient markets. Where you have a well-functioning market, the fundamentals tend to drive the price much more often than not, and market power has a very difficult time rearing its head, whereas in the less efficient market structures around the US, it's much easier for market power to rear its head. The answers are the ones I think that have

always been out there: ease eventually into the marketplace; have an interconnection standard so that generation can get built relatively quickly to deal with scarcity issues.

One of the lessons in California, whether or not systemic market power was being exercised, is that demand side responsiveness could have had a dramatic impact early on the price of power. As California began to get its act together around the demand side issue, the price of power began to come down, I would argue, even before FERC put price caps in place. Demand side responsiveness was having a dramatic impact and may well have precluded the situation from ever arising, had you had a significant demand side response available at the very outset. Even if a generator has the ability to withhold market power, that market power can be very quickly negated when you have a significant demand side response.

Of all the protections against market power now, the one that seems to get the least airtime, and is perhaps one of the most important ones is demand side responsiveness and making sure that large industrial consumers have the ability to respond. We may well be able to build the best RTO or the best transco in some parts of the country, but unless we have direct access in demand side responsiveness as part of the landscape, I'm not sure that we avoid some of the problems seen in California and perhaps other parts of the country over the last few years.

Should policy makers be concerned about another large trader? The answer is generally no, except that on a regional basis, one needs to pay attention to some of the entities that have a significant market presence, and that also may have a significant transmission presence. The issues around vertical market power are still omnipresent. The ability of some of the players who have built rather large,

unregulated businesses is still a significant concern for policymakers.

The question that was an issue in California is an entity like Enron that didn't have assets for the most part in the western part of the US or really anywhere in the US, being able to exercise market power. Enron essentially traded on information. What it got very good at was building systems that internalized a lot of information about the marketplace, and then allowed people to make Vegas gambling, or you could call it intelligent judgments. There are others in the marketplace with similar capacities. If you've got good information, you may well be able to take advantage of market power trends or market power that's being exercised by others or that you've been able to identify by reason of the information you've developed as a trading organization. That ability to exploit from a market power perspective in the context of a trading organization like Enron is ultimately a derivative of the market power of others. It's not actually the market power that the entity has in the marketplace. How do policymakers respond? This is perhaps the 64-million-dollar question for FERC. It obviously sees a dysfunctional marketplace in most of the US and significant market power, whether vertical or horizontal, being exercised. The right response is to get markets working and to put in place the institutions that will hopefully negate much of the market power they seem to see out there. The dilemma for FERC is how to identify the market power. You end up with the supply margin assessment approach that confuses scarcity with market power and may well be an overly blunt instrument.

I think there has to be some understanding of FERC's dilemma. It doesn't seem to have the ability to fully identify where the market power is being exploited, and so it tries to come up with tests like supply margin assessment which may well be

simplistic and confuse scarcity with market power, but nonetheless are a response to a legitimate issue. During the transitional period, FERC is going to have to grapple with the market power issues and somehow induce the right behavior, and drive the offenders to the solutions, to the institutions needed to make the markets more effective and that would, in time, negate the market power that arguably is out there.

Speaker Four

I will talk about manipulation and related market power concerns from a futures industry aspect, both in terms of the issues that we look at, and in terms of court cases where we've actually filed suit for people in alleged manipulation cases. For the purpose of discussion, there are four broad categories of transactions in commodity markets: spot, forward, over-the-counter derivatives, and futures and options. The different types of trades can be characterized both by the nature of the trade and the participants involved, progressing from spot to forward markets, and then the more sophisticated financial OTC derivatives and futures markets.

A few definitions, starting with the spot market: it's simply an agreement between two parties where the seller agrees to deliver a specified quantity and quality of a commodity at agreed-upon price for immediate delivery; a basic commercial or merchandising type of transaction. Forward contracts, from the context of futures regulations, have similarities to spot transactions. They are agreements by the parties to deliver a specified quantity and quality at an agreed-upon price, the difference being it's for a specified future date. For forward contracts, delivery is expected but may be deferred at the convenience of the parties involved, or there may be netting of the positions. These are generally commercial transactions, but also provide a financial risk management benefit by fixing prices

for the parties involved. Over-the-counter derivatives are a financial instrument that may have different names in different markets, different types of swap contracts, cash settled forwards, et cetera. These are bilaterally negotiated contracts, although there may be master agreements that include certain terms. They're generally settled in cash. They're not used for merchandising purposes. The cash settlements may be based on prices in futures markets, which at times can create issues because it may create incentives to distort or manipulate the futures prices to profit on the over-the-counter transactions. For over-the-counter markets, counterparty risk is an issue. Futures contracts are like over-the-counter derivatives in that they're primarily financial tools. The primary economic functions are hedging, price discovery and price basing. Any physical or merchandising type uses of these markets is generally secondary.

Some of the key features of futures markets are that they provide for delivery in the future like a forward contract. They have an offset feature that is probably the primary distinction because there's an expectation that the contracts will be liquidated prior to delivery. Again, they're used primarily for risk shifting or for assuming risk, and they usually are traded on an exchange with a clearinghouse, standardized terms, margins, and they're public markets open to all. Summarizing the types of contracts that can be used for risk management, there are forward contracts, although their primary function is physical merchandising, various OTC derivatives, and exchange-traded futures and options.

Forward markets initially may have more producers than users and the primary focus is physical trading. But as the markets progress, there may be more merchants or other intermediaries involved, and the markets may have some more financial-type trading, not just physical trading. Next in the progression

are more sophisticated over-the-counter derivatives and futures markets where you basically have all segments of the industry involved, merchants and also professional speculators. The general public may be involved in futures markets, but not necessarily in the derivatives markets. These markets are mostly financial trades. The number of contracts that actually go to delivery can be as small as one percent of all the trades for a particular month.

The increasing amount of financial trading with new participants involved in the marketplace may create potentials for manipulation and price distortion. Primarily this may result as the number of financial trades may exceed the overall available supplies of the commodity at the time the contracts mature. The markets may then become vulnerable to manipulation and price distortions.

Financial traders who may have entered into the market decide not to offset their positions prior to maturity for bona fide commercial reasons. Also, entities that may control supplies or access to information may choose to exercise their market power as the contracts near expiration. They may be firms in the business or others such as speculators.

What is futures market manipulation? Based on various court cases, it's any planned transaction or behavior intended to cause an artificial price in the futures market itself, or in relation to other markets. An artificial price is a price that does not reflect the normal forces of supply and demand. A manipulator attempts to use its dominant futures or cash market position to distort prices in the market for its own benefit. A corner is control of the available supply of the cash commodity for the purpose of influencing prices. A squeeze in the context of futures would be a dominant, long futures position that exceeds in size the amount of the commodity that may be available for delivery at the time the contract expires. In

futures markets, there have been long market power manipulations where a dominant long trader tends to cause an artificially high price that would include the typical corners and squeezes. Short market power driving down prices by making or threatening deliveries whereby traders are forced to liquidate short positions -- where they can liquidate their short positions at a profit are not as typical, but there have been several cases. Buying or selling in a manner calculated to produce an abnormal effect upon prices has been more commonly observed where a trader may try to move the settlement price at the close, again maybe to profit on positions it may have in an over-the-counter derivative trade. Finally, there are examples of issuing false reports of conditions that affect prices.

Why are manipulation, price distortion and other abuses of concern? The reasons are that they adversely impact the economic functions of the futures markets by undermining the integrity and credibility of the marketplace; make hedging less effective; may send false signals to commercial users, regulators, etc. Many futures markets are a service of primary price discovery and price-facing vehicles. They also may result in uneconomic cash market transactions and abnormal movements of the commodity in commerce.

An example of harm caused by manipulations was in 1979-1980 when silver prices moved from \$5-50 an ounce over an extended period of time. There was evidence that this affected photography, flatware, X-ray film manufacturers, and the prices of consumer goods with silver components. There was even a report of increased home burglaries to try to sell the silver products at the inflated prices.

The 1989 soybean manipulation seemed to have some impacts on farmers' confidence in the market. You may be aware that

throughout the 90s, the federal government encouraged farmers to use various market mechanisms rather than government price supports such as agricultural trade options. Many of these were difficult to sell, and part of the reason may be the undermined confidence in the futures markets due to the manipulation in soybeans. There were movements of copper into warehouses, which was out of the normal channels, and then the copper had to move back after the manipulation was over. It had a major adverse impact on the Comex that was not the subject of the manipulation, and it also affected prices paid by consumers for manufacturing.

A final example was a short-side manipulation of potatoes in the late 1960s and then in the 70s on the Nymex. Both cases resulted in uneconomic movements of potatoes to the futures delivery locations. The manipulation almost threatened the viability of the exchange. A positive side to that focused attention on other alternative markets, and Nymex spent a lot of effort and tried to develop its energy markets. These manipulations effectively undermined confidence in the potato futures among the industry, and producers in particular, so that later efforts to establish potato futures have been unsuccessful.

In considering the potential harm that may be caused by manipulation, Congress has addressed this issue with respect to futures markets since the 1920s. Federal concern focuses on the fact that the economic benefits to futures markets go beyond the exchange and affect individuals, industry, the economy and the international economy. Economic harm that may be caused by manipulation is broad and extends beyond the exchange involved.

In 2000, Congress significantly amended the law governing the regulation of commodity futures markets. It set up a new statutory framework that is basically

determined by two criteria regarding the susceptibility of commodity manipulation and the types of participants that may be involved in the marketplace. The law includes various exclusions or exemptions for dealer markets and OTC derivatives, and establishes a tiered regulation for exchange-traded instruments.

For exchange-traded instruments or futures exchanges, which in the law is called designated contract markets, any type of participant is allowed to trade on those markets and can trade any type of commodity. They have to meet certain designation standards and eighteen core principles. The products listed by a designated contract market cannot be readily subject to manipulation. A key part of CFTC oversight focuses on that core principle, ensuring that contracts listed are not readily susceptible to manipulation.

The three aspects of oversight include contract design requirements. Exchanges are required to either seek prior approval of contracts before listing, or certify that the contract is not susceptible to manipulation based on criteria set forth by CFTC. CFTC also has a market surveillance program – the daily ongoing monitoring of the markets. Finally, it can take enforcement action against alleged manipulators. Of course, this is an after-the-fact issue.

Contract terms must conform to the cash market standards and have adequate deliverable supply. In this context, deliverable supply generally is the amount of the commodity that reasonably can be expected to be available or made available at its economic value to traders involved in delivery. Generally, this focuses on an evaluation of supplies that are typically available in spot market trades. The assumption is that most traders are going to liquidate their futures positions prior to delivery, and those involved in delivery would need to go into the spot market to purchase the commodity to make delivery.

On the flip side, those that take delivery have the ability to resell the commodity at its normal value in the spot market. This consideration assumes that not all product is available for delivery. Some product may not meet the terms of the contract, or making it available would involve uneconomic movements. It also excludes any stocks that may be committed to other uses. If the spot market activity is not sufficiently liquid, then there may be other requirements imposed on the futures markets, such as speculative position limits or other surveillance requirements that the exchange has to adopt to ensure that the market isn't susceptible to manipulation.

For market surveillance, CFTC receives reports from all traders in all markets based on specified reporting levels that are set by market. It is in regular contact with the exchanges, and whenever there is a potential issue about a manipulation, it contacts the exchange, the trader, the clearing house, and attempts to jawbone the trader to take action to reduce its position or to make sure that the market closes in a satisfactory way without any price disruptions. If that fails, there are various emergency actions that the commission can take.

There are some exchanges in the US that attempted to trade a number of electricity futures contracts, like the Minneapolis Grain Exchange, but that don't trade currently. I think some exchanges thought that the electricity futures market was going to be very successful, similar to some of the Treasury markets. They were looking at the huge underlying market, price volatility, and the commodity's relative uniformity. You don't run into problems with trying to specify terms to cover various different types of grades and qualities; and with deregulation, there are many new firms in the business needing sophisticated risk management tools.

Why did the exchanges fail? Reasons cited include a fragmented underlying market; that electronic or Internet trading, dealer markets and OTC products may have replicated some of the advantages of a centralized futures exchange; that the contracts were inappropriately designed; that the month-long delivery process was not conducive to providing for an effective risk management tool in the electricity business where the concerns may be day-to-day or hour-to-hour.

Before exchanges can list futures contracts, they have to certify that they're not susceptible to manipulation, and CFTC has to make an assessment to that effect. The commission generally focuses on the traditional. Corners and squeezes are not major concerns, since you can't buy electricity and hoard it. Manipulation potential generally would focus on control of generation and transmission capacity. Other concerns are the potential for default or a trader's inability to perform on the contracts.

The exchanges have adopted what they call product placement rules to address some of the unique attributes of the electricity market. Essentially, these require traders to demonstrate to their clearing members that they have either a generation capacity or transmission availability to honor the terms of the contract, both from the side of the short who is going to deliver and the long who is going to take delivery, and if not, the clearing members are instructed to close out their positions.

In general the product placement rules and the surveillance by the CFTC and the exchanges and the speculative limits that have been adopted for the markets mean that the exchanges are not readily susceptible to manipulation, although the markets never really reached a threshold of activity to test whether they would be subject to any sort of abuses. The exchanges may be rethinking some of the

terms of the contracts, and may eventually try to launch them again, but only time will tell.

Question: Thinking in terms of analogies to electricity, it sounds like market surveillance might be something that happens once a year, or that CFTC might be actively involved every day, in real time monitoring. How much goes on every day?

Response: It's not real time, but it's close to it. Every day CFTC gets positions, sizes from anyone who has a reportable position in every futures market, that is, we get them the next day. If a trader may have a position that's very large relative to our assessments of the supplies for the commodity or relative to the market as a whole, it would contact the exchange, and then the trader or the clearing member on a daily basis whenever there is a potential problem. It's regular daily oversight. Staff are assigned or who specialize in the particular commodities follow those markets regularly.

Question: Is the physical availability of the product a measure of how much was traded on a particular day?

Response: It's a proxy, or a way to estimate, or to make a determination as to whether any particular product is susceptible to manipulation. For new markets, obviously, you can't look at the performance of the futures if it's a new product. CFTC generally tried to look at how much is typically transacted on a daily basis in the spot market, the presumption being that at the expiration of a particular futures contract, if one were short and needed to deliver, they could go into the spot market, buy the commodity and make delivery. The commission looks at is how much is typically available in the spot market for delivery so that one could acquire that to satisfy futures positions. It's a little bit of an art more than a science. But it's based on supplies that are

traded and then trying to get estimates of how much typically may be locked up by forward contracts or other commitments, and trying to derive an estimate of what typically might be available to traders for that purpose. It doesn't limit the amount of trading in the futures market. It's essentially a way for CFTC and the exchange to make a determination whether a particular contract is susceptible to manipulation, which is one of the requirements in the law. Looking at the supplies that are traded, CFTC might look at is how much of what is available is traded on a daily basis. The determination involves discussions with people in the industry about the normal transactions in the spot market. CFTC doesn't have expertise in every market. The commission talks to people, or if there is a widely developed spot market, there may be published information.

Comment: I may buy and sell the same contract, then buy the same contract again later in the day. That would be reflected in the report of exchange statistics as three contracts traded. From a point of view of manipulation, at the end of the day, how much open interest is there? We like the fact that there's a lot of trading because that gets more price discovery and it makes for a more efficient market. But if at the end of the day, there is more open interest than delivery capacity, then somebody can't deliver on a contract that they're obligated to deliver somewhere. As the contract nears the prompt delivery month, the rules for how much of an open position any one trader can maintain need to be squeezed down so that by the time you get to the delivery month, you get a convergence between the forward price and the spot price.

Response: CFTC's oversight basically involves monitoring of the positions through its surveillance function. If it looks like there's a problem or if there are price spikes, then CFTC contacts people to take action.

Question: What is CFTC's role in the private trading exchanges such as EnronOnline? A lot seems to have developed since Congress liberalized the law. Why would anyone want to go to a regulated exchange that has all this monitoring when a private exchange option is available?

Response: CFTC adopted several exemptions in the early 90s for energy contracts and swap contracts. If they met the criteria that they were involved between eligible parties, et cetera, then people could operate outside of CFTC jurisdiction. The Commodities Futures Modernization Act of 2000 essentially codified those principles, so that dealer-type markets and various electronic trading facilities between eligible participants, like large, financially capable traders were really exempted from CFTC oversight. The exemptions do not go to trading between non-financial markets that are on a trading facility and that involve the public, or anyone who can participate on the markets. A number of exchanges, but not electricity, have sought approval or designation as contract markets or futures exchanges in the last year. There may be several reasons. They don't want their markets to be restricted just to eligible participants. Some view regulatory oversight as being beneficial in terms of marketing, or as a passport to offering their product overseas.

Question: You say corners and squeezes are not of much concern in the electricity industry because there is no storage. My intuition would have said it might be the reverse.

Response: It might be how you define the terms. If you look at a corner such as in the silver market where you're buying the commodity and holding it, I don't know how you do that in electricity. I think the real concern is ownership or control over the transmission or the generation

capacity. Some of this might just be the difference in terminology.

Question: With electricity, is it possible to distinguish sufficiently between the commodity and the capacity that produces that commodity so that you can say with any confidence that control of contracts doesn't give you control over the commodity; that you can draw that kind of separation in determining what leads to market power?

Response: I'm not sure you can make that distinction. With futures contracts, as they approach expiration, there was the concern, or would be the concern if the markets were reactivated, that a trader with a large long position could attempt a squeeze-type operation by demanding more of the commodity than is available in the spot market. I'm not sure that's really significant. If you don't have a place for the power to go, I don't know what good that would do if your position is excessively large, which is why CFTC's main focus then was on traders involved both with shorts who go through the delivery process, and longs taking delivery who have the capacity both to move power to the delivery point and the ability to move it away once they took delivery. Probably the cattle market is somewhat similar in characteristics. Cattle are very perishable. Once you take delivery, you've got to do something. They lose weight very rapidly. You may be able to redeliver them, but within a few days, they're really not deliverable.

Comment: There's a very practical difference between a contract and physical asset. Physical asset seems to be a complex structure of forward obligations and forward rights. I have an option to close a plant, for example, and embedded options within that facility to buy different types of fuel, to switch fuel, to deliver to different points. When I hold a physical asset, I own both forward rights and commitments and options to make future

decisions. Typically, a futures contract tries to get a single delivery point so that you get rid of that complexity. If we equate a pure commodity with that future, such as delivering megawatt-hours in January 2002, there's a clear distinction between the physical asset and the commodity that's actually consumed.

Question: What role should energy companies have in advocating for an efficient market structure in light of the fact that it's so lucrative to be involved in an inefficient market structure? I point specifically to Enron's role in the initial formation of the ideas and the basis for California's market structure.

Response: The simple answer is that maybe you make more money in the short run in an inefficient market. But inefficient markets are politically unsustainable and, therefore, if a company is thinking about itself in a sustainable fashion, it's going to make sure that markets are as efficient as possible because it creates the income and revenue strength for the longest period of time. I don't think anybody can lay claim or even point to what ultimately emerged in California as being attributable to any one company. It ended up being a six-headed monster that may have had pieces that had been advocated by various parties. There is a tendency now to rewrite history. That doesn't add to the intellectual debate that should ensue in the lessons learned from California so that we don't replicate those mistakes in other parts of this country and other parts of the world.

Comment: PJM's members feel the same way. However, that's not to say that from time to time, some clearly don't see it in their interests to take short-term profits out by taking advantage of or trying to design imperfection to the market.

Question: The conduct-related exercise of market power is one of the two areas of responsibility FERC has in looking at the

market power issue. Market power also arises, though, in first transactional review responsibilities, as well as those of DLJ and FTC. How would you extrapolate the area of combination of physical and financial conditions when FERC is looking at the combination of two companies from a transactional point of view, and how would you establish prospectively where market power might be of concern?

Response: I'm not sure how what type of an oversight program FERC would have to set up. One would have to look at the aggregated positions both from physical trades as well as financial trades. I'm not sure if on all occasions, one could even differentiate those. A transaction may have multiple uses. In looking at the potential for exerting market power, one would consider the overall demand that might be created for the power from the multiplicity of the types of transactions that any particular firm would have.

Comment: The primary mechanism for manipulating a contract market would be achieving a position that has more open positions than there is physical supply. That is an easily observable quantity. If you have large trader reports on a daily basis that CFTC requires for its contract markets, then you have direct visibility on that issue. But if we look to the financial industry, there is a direct management of regulatory capital that is driven by value at risk systems within those firms. A derivatives trader is often trying to exploit momentary changes in the price of the contracts it trades in, from day to day as they go up or down, in a manner that keeps the value that's at risk low and earns a margin. Part of the Enron Online model was to get a lot of throughput, sort of like a grocery store. Even though the margin was low, the volume would make up for it. If you directly manage or have visibility on the value-at-risk, you could determine the traders that might be taking a very large speculative position that would go at

variance with the normal lower risk or value at risk trading philosophy. A lot of trading systems internally already do that for a lot of derivative traders.

Comment: There is a very high probability that Enron, within the absence of having any physical assets or control over any physical assets, was able to exploit market power exercise by others, but not able to actually do it itself. I can make a case that at least in a well-designed market like PJM the inability to deliver is exactly matched by the inability to take. Because of the lack of inventory, you can't force somebody to deliver and pay more than the spot price because they just say, "We'll take it right there at the Western hub, and I'll buy it for you at the Western hub, and you take it." If they can't physically take it, they have to sell it back to the hub. It's the same as liquidating the contract at the spot price. Given this situation, how you actually manipulate this physical market is difficult. The first is the line outage case, if the line was going to be out for maintenance and then people made a lot of money on the FTR market. Maybe that's bad behavior or insider trading, but it's not market power in and of itself. It's just that there was going to be a scarcity and somebody was going to make money off it and found out before everybody else. That's the insider-trading problem.

The FTR in the day-ahead market on the radial line is unsustainable because a trader can offer to sell a counter flow in that same market, and then profit because they don't actually have to deliver if they've correctly forecast what is going to actually happen in the real time market. The fact that it happened at all is best explained by saying people were confused, or there was a transition or something. But it couldn't be sustained for very long, and I don't see it as an exercise of market power.

In the capacity market case where the demand changed on January 1 confirms

the conclusion because it has the character. The contracts actually are transferring control of the physical asset that's going to be recognized in the real time when you have to meet the test. It is consistent with controlling physical assets in the real time by way of a contract, but nonetheless controlling the physical assets, as opposed to a strictly financial contract where you don't have control over the physical asset.

Response: I agree that the FTR issue is a question of access to information. I think it is purely financial, but no one was necessarily in a position to make money from it. If there was no information ahead of time, no one would have taken the FTR position based on that and therefore, the congestion simply would have occurred. On the radial line, as a matter of empirical fact, it unfortunately has been persistent. PJM put a rule in place in January 2001 to basically recapture the FTR profits when people engage in that activity. The activity has continued to be persistent in identifiable places. One would have expected, if your theory were correct, that arbitrage would correct it. The ideal situation for someone to engage in this behavior is online, which is very nearly at its thermal limit. You need to add only a slight amount of flow in the day ahead for the FTR to be valuable. It then makes taking the counter position potentially risky. Ideally, one would imagine arbitrageurs would step in and simply reverse that. I think a reason it doesn't occur is that the arbitrageurs will incur some risk and the potential profit may not be worth it, because if you only have five megawatts in order to congest the line, taking the counter position is limited to those five megawatts, or even four. I disagree on the capacity market as well. Strictly speaking, PJM's is a capacity credit market, which is purely a financial construct. It's not so much that one has the rights to the physical capacity. In fact, what you're buying is a call on the energy when it's needed in an emergency. For

most times of the year, including the period when people were paying a lot of money in the early part of this year, it wasn't necessary for liability. The call option expired without value every day. The entity that profited entered into contracts to get more of the capacity credits so that it was in a position at the beginning of the year where people had to buy from it. It almost seems as if capacity in a sense is storable, as it's not electrons, doesn't require deliverability and might have some of the attributes of more traditional physical commodities.

Comment: You raise three distinctions that are useful, and that is to separate the option and information I have from my exercise of market power, which traditionally, would be considered control of physical production capacity. An option is really just a financial right, but not an obligation to run the facility. It is immaterial whether I own that right because I own a physical asset, and then sell the right as a contract to somebody else. Maybe I just operate the facility, and somebody else has the contractual right to exercise that decision, and might then monetize it or sell it in a market. The distinction of information is important because historically, information per se has not been considered an exercise of market power, but an insider-trading problem. We're now introducing weather derivatives. Are scientists at the National Weather Service to be considered insider trading if they take a look at the last model run and then call up their futures broker? That is a real issue if we think information itself is a market power issue because there's a great diversity of knowledge of people observing electric systems at different levels of detail and aggregation, and having an understanding that they then translate into a forecast of a future price for electricity. If my price forecast is greater than the current market price, then I should be able to monetize my advantage. Today I can do that in the corn market, in natural gas markets and in a

whole variety of futures markets to take advantage of the proprietary knowledge I have. People who have knowledge make decisions on that knowledge. That's not market power per se, although it may be a regulatory issue that we want to control.

Comment: We have dimensions of action, intent, success, and profitability. If you withhold capacity, that's something that could be construed as market power and manipulation. But if you make a mistake, like a plant manager who drops a wrench in the wrong place and the plant shuts down, it has the same result. That seems to be different from withholding. Looking at marginal cost tests, I could make what you would perceive to be an irrational decision. I'm the CEO; I've got a visiting dignitary coming to my plant. I want it spiffed up and I'm going on vacation next week. Shut it down, and I don't give a damn what's going on in the market. Another example: I study how the ISO rules operate every day, and I know under these conditions market prices are going to go through the roof because I know pretty closely where the vertical demand and supply curves intersect, and so I'm going to name an outrageous price because I can.

The intent dimension is to affect the market price. That is market manipulation, but not necessarily enough to be market power because in the case of market power, you have to succeed, and do it profitably. It doesn't seem to be the case for market manipulation; you just have to try, according to the definitions. You can try and lose money but potentially still be prosecuted. Fundamentally, I'm concerned that the public perception issue is, are people making money? If at any time, the price exceeds what they can in a concrete way prove is their marginal cost at that point in time, that means there's something bad there that needs to be punished or to have profits taken away. If that's really the issue, we're in real trouble in terms of having something that's fair and what we

would think of as a working market, but would also be supportable by the public.

Question: Is there any useful distinction between the existence and the exercise of market power, or does the existence of market power just imply that it's going to be exercised without implying market manipulation?

Response: The relevance of market power is the exercise of it, not the existence. I'm not sure why the visiting dignitary would rather see a plant that's shut down and brightly polished than one that's actually running and making money. That's another question. I'm not sure what market design you're referring to when anyone can or appear to be offering energy, and at more than marginal cost they're immediately penalized and profits are taken away. In PJM markets we don't attempt to retroactively either change the price or take people's profits back. Nonetheless, it makes sense to have as objective a measure of market power as one can devise in the interests of customers as well as energy producers so that everyone can understand the rules. As I indicated, the marginal cost test is complicated to implement because there are things in marginal cost besides the fuel and variable O&M. The intent is to design markets where you have a competitive outcome. The marginal cost test is a reasonable measure of the competitive outcome.

Comment: In enforcement cases in bringing manipulations, intent is a key aspect and a difficult concept to nail down. It may go to looking at specific actions or transactions that may not appear to make sense, or maybe a smoking gun where you have letters or correspondence or something from particular people at a firm. How regulator structure or oversight structure is established for the electricity markets is a difficult concept. For futures markets, there really is not an insider trading prohibition per se. The assumption

is that the markets are available for commercial or risk management purposes. If you have knowledge of a position to be undertaken or production or whatever, then you are allowed to establish that position with the full knowledge of that or any other information about the marketplace. For something like a weather contract, which might be cash settled, the CME did propose various weather-related contracts which CFTC approved and issues about premature access to that information were considered so that anyone at the weather service or whatever would not have premature information about particular prices before they were released to the weather bureau for use for cash settlement.

Question: Is there a prohibition on the weather service doing this?

Response: They're not allowed to trade futures. It's prohibited by their employer, not by the exchange.

Question: Suppose the employer didn't have a rule?

Response: That has come up for example in some of the livestock markets where the USDA had various prices they put out that the Chicago Mercantile Exchange wanted to use for cash settlement. CFTC went to USDA before they started trading them and they set up special lockdown procedures in the release of information, which they had not done before. The prices couldn't be used for trading purposes so they did make some changes to prevent premature release.

Comment: I share the concern about public perception and the implications if we don't deal with the issues. We're at a point where we know what market power is and when it's being exercised. Whether information can ever equate to market power, we know how to resolve the one-sided nature of information by getting as much of it as possible into the

marketplace, something that we still struggle to do. We know the answer around generation and transmission market power and how to mitigate them. We know what kinds of institutions are needed to ensure the proper separation of generation from transmission. Yet as an industry we're ten years removed from the Energy Policy Act and we're still debating the nature of the institutions and whether we really want to do it. We know that it's necessary. But we continue to get hung up on the definitions, and part of it is people hiding behind definitions, dancing around parochial agendas on behalf of their companies or institutions.

Comment: There's no question that electricity today doesn't have the attributes that make for a good and efficient contract market because there isn't sufficient volume of contracts divorced from the physical supply. We still measure the success of electronic exchanges in contracts for electricity as a percent of the total notional value of wholesale electricity that's bought. Yet if we go to well-functioning futures markets, we see contract volumes that are in order of magnitude greater than the physical delivered volume. It's that kind of contract flow that creates efficient pricing and makes attempts to manipulate the price very risky and speculative. Most of the great derivatives disasters were caused by companies which deliberately or unintentionally took huge speculative positions in some basis differential. At one point they might own 30 or 50 percent of the contracts on one side. Eventually, that begins to cause a problem because it becomes known in the marketplace that they're going to have to unwind that position. And as soon as it becomes known that they have to unwind that position, other people do what's called front running. They take a position ahead of it, and then sell back, and it just drives the price against whoever has that large position. In a large, well-functioning market, it's very difficult to manipulate to

advantage. But you have to get to contract volumes that are many multiples of the underlying cash market. By its very nature, that creates transparent reporting of pricing because you have a mechanism with a lot of transactions so that the diversity of bids and offers end up averaging out. You also have diversity of order flow, a lot of orders on both the buy and the sell side so that the middlemen who are basically taking orders to buy on this side and matching them up with orders to sell on this side, have a lot to work with. In electricity we have had a lot of producers that have value at risk systems that tell them they want to manage risk to a lower level. And then we have regulatory structures that essentially prevent regulated utilities from doing the counter-parting, taking the other natural side of the hedge. That has had an unintended effect of asymmetrically changing the flow of buy and sell orders into an exchange, whether it's Enron Online, or a Nymex exchange. Those are well-studied features of successful futures markets in other commodities. There is no reason they can't be replicated in electricity.

Comment: Some have said that Enron's demise didn't have anything to do with power markets, but it did isolate some defects in the markets, such as Enron Online's lack of transparency. I think the transparency is cost transparency, what's the cost to people. We have to worry when government leaders go to cost, cost, cost, because if we look at the entire industry of this country, it's not based on cost. You don't ask what it costs Ford to build your Expedition; you ask if this is a reasonable price. Whether we'll step up to the plate to be the market maker, the early bird gets the worm, and the second mouse gets the cheese. I think there are a lot of second mice out there, but there are a lot of people trying to step up to the plate. I think where we always fall apart in terms of definition is the scarcity rent versus market power. To me, that is a matter of

timing. You can have market power instantaneously, or for a couple of weeks or you can have it for a couple of years. When you get to the power business, despite some exceptions, it takes 30 to 60 months to build a plant. How do we deal with somebody who has market power during those 30 to 60 months? I think we could all agree that price controls are not the answer. Transmission access is a big part of the answer: if I'm in a load pocket and nobody else can get in, I may well have market power. But if there's transmission to get in, and four or five competitors, it dissipates just like that. Related issues are how do you make sure there's access to existing facilities and efficiently garner capital and the political will to build new ones? The only immediate answer in my mind is demand response. It's hard to get it in place quickly because these programs take five or six years to get up and running. There are also jurisdictional issues. Is there a deal where, in return for market mitigation, the states have to show that they've done something in terms of demand response? FERC tried to do that in telling California to get demand response in. Is that the short-term answer, or are we going to fine-tune all of this into oblivion, what the capital markets are doing now in terms of raising capital for generation? When it comes to demand response programs you aren't necessarily talking about a long time frame. During the California crisis there were many people, including Enron, who were proposing demand side auctions that could have been put in place in a matter of days. The mechanism is there; we see it in other places, especially with some of the on-line mediums that have developed in this industry and in others. It's the politics and the jurisdictional issues that are complex. If people were focused on putting the solutions in place, recognizing that they are essential ingredients to getting healthy electricity markets, you could do it quickly.

Comment: I can manage my risk of forward commitments if I choose to participate in a risk management program by buying forward. I can do that by exercising my right not to consume. To a large degree, we've insulated individual consumers from exercising that option because we insulate the price signal. But it seems to me that it doesn't mean we're not exercising a right not to consume. The state of California as an individual consumer or monopolist if you will, exercised quite a large degree of option not to consume. It may have been jawboning and good public policy, rather than price signal, but it was still the consumer exercising an option not to consume. The main mistake, from a risk management point of view, was buying contracts first and then exercising the right, as opposed to doing it the other way around.

Comment: I don't think there's any necessary inconsistency between having retail price caps, which we have in most PJM states, for example, which would be in place for some number of years, and having effective demand side. There's still a spread there. If the price in the wholesale market is \$900, and you have to sell retail for 60, obviously, you're not going to make that up on volume. There is an intermediary market where optionality can be valued and sold back to the customers, regardless of their retail rate.

Comment: The gaming of constraints has been a problem that we've had for years. You could have a regime where it's unfair for one person to have information and another not to, so let's make it all public. TransGrid in Australia made information available about major outages of transmission lines and announced when it would take place a week after the introduction of a new market for frequency control ancillary services. Enron rang up TransGrid and said you make sure you stick to this outage because we've taken positions on this. The effect in

the first week of trading was the exercise of a lot of market manipulation. I'm unsure of the bright line between market power and market manipulation because you have to be in a pretty powerful position particularly with physical assets to be able to manipulate the market.

You can say that you won't make the information public. That takes you back ten years to what happened in England and Wales where the large generators had a lot of ex-system operators on their staff, and it wasn't so difficult to build a model of the way in which the national grid system actually operated under certain conditions. They could actually anticipate when the constraints were coming up and were able to game the constraints with that institutional knowledge. Why is this a problem that we haven't fixed after all this time?

Response: PJM and others including FERC have come down on the side of making information public. The cause of some of the issues really had to do with the interaction between the timing of an FTR market, that is, the ability to profit from congestion, and the publication date of that information. It was an unanticipated consequence of introducing the FTR market. The answer is to make the markets as transparent as possible; to make as much information public about transmission outages as it's available to the transmission owners.

Comment: In studying the summers of 2000 and 2001 in California, that really wasn't enough time to get a lot of new entry, though there was some. Demand side was also a solution. We obviously didn't upgrade any transmission. One of the biggest mitigation measures for market power is forward contracts. I'm not recommending the forward contracts that California signed, but if you have suppliers who essentially promise to deliver to you at a fixed price, then they don't have a lot to gain in manipulating the

spot market because they have less on the margin which they can profit from. That was one of the big stories in terms of market power mitigation that people should remember. When asking if you have to have the physical commodity to manipulate the price, Enron didn't have the physical commodity. It was a fairly large supplier in our spot market until November 2000. In the period we studied, it was bidding very aggressively with its power. It also had times in which it was long and could manipulate the price in order to benefit that position. When you're a supplier in real time, you do have a physical position. You are delivering. And the bidding is very high for it. There are many ways to translate your financial position into impact on physical prices.

Comment: An observation about basic symmetry in financial contract markets is that anything you can do on a long position, you can do on a short position. I can trade around a long position if I'm a producer, and I can trade around a short position if I'm a consumer. We tend to talk about market power purely from a producer point of view. But many commodity markets have extremely significant buying agents, as well. All of the tools and techniques of buying and selling contracts that are used for risk management purposes are equally applicable on both the long and the short position. If I'm Coca-Cola and have to buy a great deal of aluminum cans, I can trade around that position and can both manage my risk by buying and selling contracts on the LME, and if I have a sufficient control of inventory, I can, to a degree, exercise market power as a buyer -- not as a seller and producer. That aspect of market power has not been explored very deeply.

Comment: The state of California was the buyer, and yet it was unable to figure out a way to exercise any kind of market power on that side of the bargain.

Comment: When you're a very large position taker, whether it's a short or a long position, and you publicly disclose your intent and your need, or inevitably disclose it simply because of your natural position, you're in a weak bargaining position. California's consumers have that position. The way you manage that risk is by dynamically changing your net position through contracts. That doesn't mean you want to be 100 percent hedged or zero percent hedged, but that you dynamically control that up and down in response to changing prices so that you have as low a risk net exposure as you're comfortable with.

Comment: The California ISO did a tremendous job of leveraging its monopoly position in the years prior to 2000-2001, so it cuts both ways.

Comment: As markets have become more dominant, more of what we used to call utilities and now call load-serving entities are buying more of their power in the marketplace rather than generating it. We've got one utility that buys half of its power that it sells in the marketplace, rather than generating itself. As a result of exposure this spring, it had to raise its power cost by nearly 200 percent. We ended up passing on a rate increase of over 50 percent to our largest community in the state and to our industrial base, essentially taking a huge number of dollars out of the state and sending them somewhere else. This has had political consequences, to say the least. I have no problem with having prices go up when the costs of actually producing energy go up. But when they go up and down, and up and down, they send terrific signals in the economy that can have devastating effects. As a regulator what can I do to encourage my utilities to reduce this volatility?

Response: Last winter gas prices went up quite precipitously across most of the country. The load-serving entities adjusted

their fuel adjustment clauses quite significantly. Rates went up anywhere of a hundred percent. These gas LDCs were on hedge for the most part, with very little locked in hourly - the equivalent of the daily market in the gas context. The LDC's made that decision because regulators historically have been very reluctant to share the risk with these companies in putting together more balanced portfolios. Typically, if you bet right you got to recover it; if you bet wrong, you ate it. There has to be a different approach on the part of regulators, that if you locked in the price of gas let's say in the winter of '99 for the winter of 2000, for three dollars when gas was selling at that point at \$2.20, you clearly ran the risk that gas was still going to be selling for 2.20 the following winter. But you also ran the risk that gas as it did happen, would sell for eight or ten dollars. You have to understand the risk paradigm, and be willing to tolerate the fact that we're better off locking in at three dollars because we've banded our exposure in a way that is better for consumers and better for the economy in the state, but also knowing that you could be in a spot where that three dollars is somewhat higher than the spot or daily price. It's been a very difficult concept for regulators generally to embrace because in some respects, politically, it's easier not to join in the bet so to speak.

Comment: A related point is that you happened to be unfortunate to be there when the prices went up and you got hit. I don't know the company or how long it pursued the strategy, but by foregoing building for a number of years and relying more on contracting in the early years, it may have saved a lot of money.

Response: That doesn't make consumers feel better about getting a 50 percent rate increase.

Comment: Then you want them fully hedged so that those kinds of price spikes won't occur.

Comment: By framing the question, "What can I do as a regulator to encourage the utility to control prices?" you've presumed that they have the ability to do that. You've presumed that they have

market power, and you simply want them to exercise it in a different direction than I think you've presumed that perhaps they have, or their compatriots have. In a well-functioning market, a utility in a small state really wouldn't have any significant ability to manipulate prices.

Session Two. Transmission Expansion: Market-Based and Regulated Approaches

The debate on transmission expansion has focused on the need for better regulatory incentives and the conditions that must be put in place to encourage merchant transmission development. However, issues are beginning to emerge at the interface between the market-based and the regulated approaches to expansion. There is consensus that both approaches are needed, but there is a lack of clarity as to how they would work together in practice. For example, how do you stop merchant and regulated transmission owners from treading on each other's toes? Both could throw a monkey wrench into the plans of the other by doing their own thing at short notice. Generation and demand side solutions that reduce congestion need to be taken into account as well. How do you handle a situation where one project competes directly with another and undermines its project economics? The key to facilitating both merchant and regulated transmission expansion and other non-transmission solutions may well lie in the planning process. Clearly there is no appetite, in a deregulated environment, for command and control-style central planning. The new is one of co-operation, coordination and consensus building. However, will this be sufficient to ensure that the transmission facilities that society needs actually get built? Does the RTO that conducts the process need more authority and are the market participants and transmission owners likely to want to give it? Will the traditional cost-benefit analyses used in the planning process account for the needs of all stakeholders? What models can be used to define what the optimum expansion and congestion of the transmission system should be from the point of view of the consumer, taking into account generation and demand side alternatives? Should the regulators and siting authorities participate in the planning process as active participants or as observers?

Speaker One

Merchant transmission is no longer an esoteric, theoretical construct. Both market-based and regulated transmission can coexist and, in fact, have to coexist in order for markets to be fully functional. How do we get to the concept of market-driven transmission? Bid-based security constrained markets, locational pricing and implementing transmission property rights in the form of financial transmission

rights. As in many other industries, technology is driving change here. This framework is proving at least to bring investment in the generation sector.

Can the two forms of investment vehicles exist in the same framework? Why do we need a regulated transmission function? I think all of us recognize that the political reality dictates otherwise. Once society

makes this decision that we need to have some role for regulated transmission, how do we determine how much, and who gets to do it, and where does it go? The details matter because they affect whether market-based transmission projects succeed and the implications are tremendous for the entire market, because regulated transmission competes against all solutions.

Can the market do it all? I still think so. But you have a very large gap between prices that lead to an efficient economic outcome and prices that sell at the state house. Given that political reality, we advocate that a central planning role is in fact acceptable, but we need to ensure that it only looks at what is needed to keep the lights on. We need to address the question of when the central planner essentially intervenes in the market to implement a particular solution.

Planning for economics: I think we implemented these markets to provide price signals so that private investment responds and economic solutions are provided. Our vision is of a planning process that has well-defined criteria for determining what constitutes a need and how we analyze it. This is not something that can be done by a legislature or by Congress. The second point is independence or neutrality. Transmission owners are market participants; they can and do affect market outcomes. That's why there needs to be an independent planner. The third point is to inject some competition into what otherwise is pretty much a centrally administered process. You don't really know what innovations are out there unless you ask. And there are creative ways to finance projects and to structure contracts. When you talk to customers, you figure out ways of managing their risks. This is no different from what a generator does when it looks at project opportunities.

A solicitation process has an open structure that allows as many bidders as possible, including the incumbent transmission owners. Frankly, they have the best tool set of all the possible bidders and should be in the best position to win all of the solicitations in my opinion.

Another point is to look at and allow innovations in cost recovery. If you want to bid a cost-of-service project, fine. I don't mean to preclude any cost recovery mechanism. My emphasis is to ensure that those bidders seeking to solve solutions be allowed to design, finance, build, own and essentially affect a solution while ceding operation to some sort of system operator.

Assess the system. Inform participants of the problems and needs. In the event that nobody comes forward with a market-driven or other solution, develop a request for solutions. Evaluate and implement. FERC has said, "We direct the ISO to revise its proposal to eliminate any decisional role that transmission owners may have in the role." It recognizes the importance of neutrality and independence in the process.

We'd like to mesh the market design process and some of the transmission planning processes in PJM with ideas from the Vencor system in Australia. Vencor has a process for identifying needs and conducting RFPs. Some of the solicitations are quite specific, for example, it put out a solicitation for capacitor banks.

A possible alternative is what I call the monopoly transmission club which almost recreates the old world through an aggregation of the old transmission owners into an exclusive club that is responsible for running the system and for doing all of the planning. It's effectively closed to any new entrants.

We believe that the PJM side of the proposal brings benefits. It harnesses

market forces to direct investments. These are entrepreneurially driven, and it's our money at risk. We're going to take some lumps and we're going to make some money. The existing grid access charge remains unchanged. Our goal is to maximize competition in all these markets.

Market-based transmission is for real. Markets can and do work. Make sure you have the right structure in place. And with that, you will see that you can have regulated transmission peacefully coexist with market-based transmission.

Question: The planning process identifies a need for transmission and no merchant comes forward to build it. Under your paradigm, who has the obligation to build?

Response: Under that framework and you need something for reliability to keep the lights on, you have to rely on the incumbent transmission owners.

Question: If I understand the planning process, it identifies the need for transmission, but not the actual project to satisfy that need. Then different people on their own propose the solution to the need, be it transmission, two transmission projects, generation. This is not a matter of the incumbent figuring out how to satisfy the need, and then everybody else gets to bid on whether they make the investment?

Response: Correct, except that the incumbent is free to propose something as is everybody else and that's why the solicitation process.

Question: How do you see a merchant transmission investment recovering cost? What is the basic mechanism?

Response: A market-based transmission investment can recover its costs in several ways. It can sell off the property rights up front to willing customers that want to in

effect, hedge a particular price difference. It can do that through an FTR mechanism of an existing ISO, through the sale of physical rights in a bilateral-type arrangement. It's our belief and experience that you can fund new transmission by the selling of these property rights up front.

Question: When generation competes, who pays for it? Is there a subsidy?

Response: If you're putting out a solicitation for a socialized cost recovery and a generator wants to solve the solution, and if that's deemed to be the best solution, the costs of that generator should be socialize; it could be assigned to particular customers. The method for cost allocation shouldn't preclude the available number of solutions.

Question: Is this a true statement: FERC Chairman Wood gets three votes for his views that all transmission upgrades should be rolled into rates. There's nothing left of your model for merchant transmission.

Response: It's an unfortunate outcome.

Speaker Two

I'll talk about what makes the merchant links in Australia different from what's going on here, specific lessons from them and regulated transmission. It is important when you're talking about experiences that the context is right. The scale in market power is very important in Australia. The gas and coal competition issue sits in our country in a way that it doesn't here because the gas market is very uncompetitive compared to the markets in North America.

Australia's land area is just a little bit less than the continental US. The US is 290 million people; we've got about nineteen and a half, a 14.4 times ratio. Most of our population lives along the eastern

seaboard. The biggest state is New South Wales and the smallest is Tasmania with 1,641 MW. Electricity use is 19.4 times the amount of energy used in the US.

We're richly endowed with black coal and it's good quality. Most of the gas that's presently used comes from two basin areas. As we mesh the network, there will be more competition between the basins. In the not too far distant future, there are major projects that ought to impact on gas supplies. My point is that in terms of competition in the energy market, we think of electricity as being a valuable way to underwrite gas projects through gas generators.

The transmission system is the longest continuous ISO system in the world. I stand a bit corrected, but it's certainly very long. It's about 3,000 miles from up in North Queensland around to South Australia. Stability is a major issue in our system. Losses are quite significant; we're up at 25 percent of load per mile, compared with the US. Transgrid looks after the system that serves the largest load area, and is largely New South Wales based. Historically, most transmission companies are state-based.

We've already got an electricity management company that is national and has a number of the ISO functions. I think a national transco will remain on the agenda in our country as an option to the ISO. Stand-alone transmission companies we've already separated, and fully separated the transmission from the generation entities. There are only four regulated major transmission owners. Together, they become by international standards, a medium-scale transmission company in terms of throughput.

Australia is an energy-only market. That introduces interesting cross-volatility issues that I don't think you experience in PJM. We have approximate nodal crossing only, a node in each state, basically.

Transmission-ISO boundary is blurry. We've had a review for two years, and haven't really resolved the responsibility interfaces particularly well.

Key policy issues include state versus national accountability. I think this is the reason why we've got lots of regulations and still a lot of state-based regulations. Vencor is one of four models that apply across the four states. It's difficult to draw conclusions about a planning process when you haven't really tried it on large amounts of capital projects, and there's also an accountability issue that needs to be worked through.

The big issue, though, is improving competition in the energy markets. I think competition in transmission pales in significance compared with that.

Cross-volatility puts up the cost of risk. The liquidity in the inter-regional hedging markets is virtually zero. We've got some real issues in getting a national market support going forward. Part of the problem is our relatively weak transmission links.

The architecture of the national transmission organization will be debated this year. Things that still need to be resolved are the transmission crossing frameworks. There's a half-hearted plea from some quarters for the nodal crossing FTR sort of things.

Regulation and merchant investment, however, hang together. Access rights probably go with FTR to some extent, and accountability for liability. I'm not quite sure how one weighs that off with other obligations and efficiency considerations, given that planning is such an important part of getting an efficient system.

Governance arrangements, getting the balance between public policy and participant interests correct, imperative neutrality, public versus private energy:

we still have a number of companies in public hands and people see that as a conflict of interest when policymakers have a commercial stake in the outcomes of the businesses.

Counter-framework for transmission investment: there's a distinction between reliability and congestion investment within the code, and within the various tests for assessing investment. There's public planning statements issued by state-based companies such as Transgrid and Vencor, particularly dealing with the reliability issues. Most of the congestion issues are inter-regional and are handled by a national statement of opportunities issues by NEMCO, which is more or less the ISO.

An investor can choose a regulator or a merchant power. Merchant gets congestion residues between the nodes.

Regulated links that pass the regulatory test receive income from a regulated transmission charge. The regulatory test is set at quite some detail. It's intended to be an open and thorough process, built around a cost benefit framework. Australian merchant links are unique. There's no explicit benefit assessment for each project compared with the way FERC does it. The checks on market power of Australian merchant links are pretty weak. We rely on competition law and competition law relies on all kinds of information coming forward, and a lot of entrepreneurial arrangements make it hard for the information to come forward. There's no open auction of rights, there's no explicit limits on the involvement of affiliates, or on the commercial arrangements between the merchant links and generators. They can effectively withhold capacity from the market if they choose. There's no use-it-or-lose-it provision.

What QNI taught us is how far the merchant link has to go to control the

transmission system to protect itself from the other players in the system. Should the merchant operator and related parties be allowed to control the link before they need to be regulated, to avoid exploitation of the market power within the regulated transmission network? We're starting to look ahead as to where this framework might lead. With QNI and DirectLink, QNI is a DC link of about 40 miles. QNI is also just being built, and broadly parallels DirectLink. It's a regulated overhead AC link 346 miles long with a basic capacity of 700 MW and growing, as we better understand the dynamics of the system. The total cost was 350 million dollars Australian, or about 1,500 dollars Australian per megawatt-mile. The benefits to date have been estimated at about 125 million dollars per annum. A large chunk of that comes from ancillary service benefits, which under our regime, the merchant link has been unable to capitalize. I think that probably invokes a few questions about whether the current merchant framework, which just kept its constraints, is really leaving the merchant links short of a lot of opportunity.

DirectLink is a merchant underground DC. It was first in operation and did very well for a few months. It's 40 miles long, has a maximum capacity of 180 MW and a total cost of 135 million dollars. That works out to 600 dollars per megawatt-mile. That's the only empirical evidence I can find that relates to the economies of scale argument.

Reliability benefits are unsettled. There are weak links into southern Queensland that a DirectLink could be useful for supporting. There is a new augmentation in New South Wales that could be avoided if we could use DirectLink for reliability support to those areas of the state. How that will work is unsettled.

The Queensland pool process with energy-only market volatility is a scary market to play in if you're a trader. If you can

reduce the volatility by whatever means, it's advantageous to the market. A significant capacity of QNI came in about February following commissioning tests, and led to a marked reduction in volatility. There has also been some new generation capacity in Queensland. The benefit is not easily measured, but reducing volatility reduces the cost of risk management.

Ancillary services before and after averages QNI. QNI's commissioning led to about 2,500,000 dollars a week savings in frequency control ancillary services.

About other projects, one needs to think about how far a merchant owner has to go to protect its position within an integrated network, and how far it will be allowed to go before it actually becomes a monopoly in its own right. How does the planning process deal with those things?

Other issues are having stakeholders willing to work with governments to ensure adequate reliability and acceptable cross levels. Southern generators must take their market position. Gas supplies must protect market growth for the gas markets in the south. What are the economies of scale in the merchant framework? The merchant proponent's commercial position may not be necessarily consistent with the overall system economics. Interaction between reliability and congestion is complex.

The transmission market in most of the literature I see is unsatisfactory from my perspective in analyzing the market as a market, and analyzing the economics. Are we talking about assets or about capability? There's still a problem with service performance.

Common good characteristics: how do you introduce net economic value as a performance indicator? ISO constraint judgments are actually a substitute for transmission investment. In our market, coming up with a constraint equation with

so much stability to deal with means if you're smarter with your constraint equations, you'll probably save an awful lot of transmission investment.

If you're going to have a nodal price, is it a price signal to the ISO, to the transmission investor, or both? If the ISO uses it as a price signal and has to respond, you've now got a moving target for all those people who are investing in capital on the ground.

The economies of scale in my view are not fully appreciated. I spent a few years in transmission planning and I know there is a lot of benefit in having things all done coherently. Elasticity of demand is often ignored.

As for the future for merchant investment, first, there needs to be a holistic approach to the transmission architecture. The architecture must suit the policy context. It's very risky for network investors to preempt this. I think the desire to harness market forces will be an inevitable driver and we need to have this discussion in Australia.

Question: On your comparison of QNI and DirectLink, are you intending to imply that DirectLink was uneconomical?

Response: At the moment, I'm implying exactly that. It's uneconomic because there's a link right beside it that does all the work. I guess the merchant link is going to have a dilemma in any price as to how they sell us this thing between those two extremes.

Speaker Three

In order to deliver low, long-term electricity prices to consumers, and consequently the best deal to society as a whole, the electricity industry has to ensure that, in the short-term, the system is efficiently operated and that in the long-term, it follows the path of least-cost

development and efficient investment. In the specific context of transmission operation and expansion, this requires a coordinated approach to optimizing generation and transmission operation and development, as the optimization of the transmission network in isolation from generation would almost certainly not meet the above objectives. Vertical integration of conventional utilities seemed necessary for a sufficient level of coordination to be achieved.

Competition and choice in electricity supply was introduced, among other reasons, to respond to growing concerns related to inefficiencies of established operation and investment practices. One of the consequences of the deregulation process is the separation of generation from transmission, frequently considered necessary for ensuring an open and non-discriminatory access to the energy market. In this environment, pricing of transmission becomes key to achieving both efficient operation and least-cost system development of the entire system. The coordination of investing in generation and transmission (now operating as separate entities) is to be achieved through efficient network pricing mechanisms. Much of the ongoing work around the world in the area of transmission network pricing has focused on short-term operational efficiency and transmission congestion management. Location specific, short-run marginal cost-based pricing is now a well-established method for allocating scarce network resources, although the approaches to computing or discovering efficient prices may vary. For example, a model based on locational marginal prices computed from a bid-based security constrained dispatch combined with financial transmission rights have been successfully implemented in a number of markets. More recently, discussion has focused on the need to create new regulatory incentives for network investment and to set up an

environment that encourages market-based transmission expansion.

A number of concerns are associated with performance-based approaches to regulation. Particular practical problems are associated with difficulties in setting performance targets and allocating the costs and benefits of transmission expansion. The proposed concept of a reference network can be applied to tackle these questions.

The relationship between short-term locational marginal prices associated with corresponding transmission rights and transmission investment is also relevant to the development of merchant-based transmission expansion. The concept of a reference network could be combined with SRMC-type pricing in order to ensure not only an efficient allocation of scarce resources (SRMC pricing), but also to establish a consistent and efficient allocation of transmission investments with appropriate investment cost recovery, by applying marginal investment pricing derived from the reference network. The concept of a reference network is a construct derived from economic theory and has a long history, although the terms “reference network” or “economically adopted network” were not necessarily used explicitly. In particular, Farmer pioneered the application of this concept for pricing transmission in a competitive environment. This approach was also used to examine the relationship between short-term locational marginal prices associated with corresponding financial or physical transmission rights and transmission investment. The application of a reference network as a framework for regulating transmission monopolies, together with an efficient implementation methodology has also been investigated.

Although the detail and complexity involved in determining the global economic optimality of a transmission network vary considerably, the reference

network, in its simplest form, would be topologically identical to the existing network with the same generation and load layouts, would operate at the same voltage levels as the real one, but the individual transmission circuits would have optimal capacities. These optimal capacities are determined in an exercise that balances the operating and investment costs of transmission, while satisfying security constraints. Clearly, fewer and smaller duration congestions result from higher circuit capacities. This implies higher transmission investment costs, but lower operating costs. If we assume that the transmission capacity can take any size with, say, constant marginal investment cost, the resulting reference network would have exactly the optimal amount of congestion to which the optimal amount of investment cost would be associated, such that the total investment and operating costs are minimized.

To balance these costs on an equal basis, capturing seasonal variations in load demand and generation operating patterns, the exercise can be performed over a time horizon of one year. In this case, the investment cost would normally be annuitized and then compared with the annual operating cost. A similar but more complex exercise is carried out in a conventional transmission expansion task. One important difference, however, is that instead of optimizing the capacity of only a few newly proposed circuits to be added, it is done for both existing and new transmission circuits.

The problem of determining the reference network characteristics belongs to a class of so-called security constrained optimal power flow problems. In its simplest form, this can be formulated within the domain of a conventional DC-based optimal power flow that includes minimization of annual generation cost and annuitized cost of transmission. It is important that the optimization covers a number of load-demand levels and takes into account

credible outages of transmission and generation facilities.

This basic algorithm for constructing the reference network can be made considerably more complex to allow optimization of the network topology and circuit voltage levels, and to deal with load growth, economies of scale, new transmission technologies such as FACTS, distributed generation, demand side management, effects of losses, reactive power, network stability constraints, various forms of generation reserve, and so forth. The appropriate degree of complexity will depend on the intended application and may also be system specific. It is important to bear in mind that the purpose of the reference network is not to replace detailed technical design of the transmission network, but to support activities and decisions associated with regulation, investment and pricing of transmission.

The optimal investment and congestion costs that characterize the reference transmission network can be quantified and then compared with the real system. Contrasting the capacities of the individual circuits of the reference and real networks, the usefulness of these can be quantified and the need for new investment identified. Furthermore, the expected reference congestion cost and out-of-merit generation cost associated with various characteristic demand levels (representing daily and seasonal variations) can also be assessed. In a market model with regulated transmission, the information is vital for addressing the question of appropriate levels of investment and operating costs that are reasonable or indeed optimal. Clearly the reference network can provide a framework for quantifying benchmark or reference costs, a necessary component of any credible regulatory control. It has already been recognized that the present regulatory approaches to a large extent, lack a clear basis for justifying particular

congestion cost and performance targets. On the other hand, a reference network could be used to establish justifiable and more rigorous transmission network performance targets associated with expenditure and reliability. Using the reference network concept, a transmission company can effectively compete with its own reference model.

A number of concerns are associated with performance based regulation approaches, such as the possibility that the transmission company could manipulate the planning process by favoring specific transmission solutions, or the difficulties in setting performance targets and allocating the costs and benefits of transmission expansion, could be addressed using a reference network. Moreover, this could be a useful tool for supporting competitive solicitation or consensus-based transmission expansion. It can provide useful information for merchant-based transmission expansion. In particular, a reference network can be used for allocating the project costs to those transmission customers who benefit from the project. As transmission investment costs are being allocated to the competitive generators and retailers, the manner in which they are allocated will influence the relative competitiveness of individual participants in the energy market. If the development of competition is to be supported, this question is of considerable interest. Otherwise, the objective of ensuring open and non-discriminatory network access to all players in the energy market will be compromised. For example, the relative competitiveness of two generating plants using the same technology, assuming equal fuel access arrangements, will be governed only by the differences in charges for the access and use of transmission, including both short-term access and use-of-system charges. In the long run, network pricing impacts on the location of new generators and demand and strongly influences the operational

efficiency and long-term development of the networks themselves. In other words, network pricing has profound implications for the overall economic efficiency of the entire electricity industry in the new paradigm. The importance of efficient network pricing cannot be overstated.

Short-run locational marginal cost pricing (SRMC or LMP) generates insufficient revenues to cover transmission investment costs. Hence, there is a need for the development of a complementary mechanism to allocate investment costs in real, meshed transmission systems. A reference network provides a consistent framework for this purpose and can be used on its own or in conjunction with LMP. As the capacities of the circuits in a reference network are optimal, there will always be occasions when the power flow through each circuit will be exactly equal to its capacity in the security constrained sense. During these periods that are circuit specific, the corresponding constraint will be active, and will create congestion and restrict the operation of the system. When the power flow through a circuit is below its capacity, there will be no impact on system operation in any way. Application of marginal pricing charges for the use of each particular circuit would apply only during the periods when the corresponding flow is binding. In this case, loading the circuit for an additional unit requires reinforcing the capacity of the circuit. On the other hand, when the flow is below the circuit capacity, charges would be equal to zero, as the incremental change in loading of the circuit does not impose any costs. For simplicity of the argument, the cost of losses is excluded. The transformation of the reference circuit to reference nodal prices is carried out by using the conventional sensitivity analysis. By definition, these sensitivities measure the impact of an incremental change in nodal injection on a particular line flow. In this case the process is reversed, where the circuit price that corresponds to a line flow is transformed into nodal prices that

correspond to power injections. Prices for demand and generation connected to the same node would have the same magnitudes but different polarities. Although circuit prices are always positive, representing circuit annuitized investment cost, nodal reference investment prices can be positive or negative depending on the impact the particular injection has on the flow in the binding circuit.

In this context, it is important to note the fundamental difference between marginal investment pricing, or MIP, and short-run locational marginal pricing. While the optimal investment price associated with a particular circuit is different from zero only when the circuit power flow reaches its capacity, the short-run marginal prices across the same circuit may be different from zero even when the flow through the circuit is below its capacity. It is well known that the presence of congestion on one circuit produces price differentials across this circuit and across many other non-congested circuits. A direct relationship between the transmission short-run marginal price across a particular circuit and the need for investment in this particular circuit cannot be established on a meshed transmission system. Strictly speaking, short-run marginal cost prices reflect precisely the need for investment only on radial transmission networks. On a meshed system, the price differentials across transmission circuits, as calculated through LMP, cannot be directly linked with the investment related to these individual circuits. However, the extent to which this effect may be significant in practice will be system specific and generally would not be a problem for interconnections.

Short-run marginal pricing may be insufficient to cover the cost of transmission investment. However, it tends to represent the greater proportion of network charges as compared with the

short-run marginal cost of transmission, and its allocation deserves much greater focus than at present. The reference network and corresponding MIP policy could be combined with SRMC-type pricing. The combination could ensure an efficient short-term operation through LMP, and a consistent and efficient allocation of transmission investments through MIP with appropriate investment cost recovery. The main feature of the reference network approach is that the demand for each of the transmission circuits and the price for its use should be determined on the reference network, not the existing (real) network. However, the prices calculated for the reference network are also optimal for the existing network of any capacity. This is important since, in practice, the actual transmission capacity rarely (never) coincides with the optimal value due to a number of factors including transmission capacity indivisibilities, historical investment programs and various technical and economic constraints. As reference investment prices are applied on the existing network, it is interesting to examine the revenue recovery in the actual network. The cases for over-invested and under-invested systems are examined followed by a comparative analysis of revenue recovery under conventional short-run locational marginal cost pricing for transmission.

In the case of an over-invested system, the system operator will take advantage of the excess capacity and reduce congestion and operating costs below their optimal values. Consistent with MIP, charges would be imposed during the periods in which the flow equals circuit capacity with respect to the optimal network. It can be shown that the benefit, if any, of over-investment will be in the extra energy delivered across over-invested circuits above what would have been delivered if the network capacity were optimal. This indicates that over-investment may provide some benefit to network users, as it reduces the level of congestion and corresponding operating

costs. In effect, congestion cost and out-of-merit order generation cost will be reduced below their optimal values at the expense of over-investment in the network. In other words, the excess in transmission capacity may not be completely wasted. The reference network-based allocation can take this effect accurately into consideration and in the case of an over-invested system, the revenue recovered is less than investment as it should be, but will always be considerably greater than the corresponding SRMC revenue. On the other hand, in the case of an under-invested system, the revenue is fully recovered if optimal investment pricing is applied. In contrast, SRMC revenue is always greater than investment, leading to over-recovery in the case of under-invested systems. If the reference network is to be used with SRMC type pricing, the revenue recovered through MIP can be adjusted to take into account the revenue recovered from selling firm access rights.

Marginal investment pricing, derived from the concept of a reference network, can be used to establish a consistent framework for allocation of transmission investments. This is essential for facilitating the competitive solicitation process for transmission development if project costs are to be allocated efficiently among

Speaker Four

PJM is very much an information company, as well as a technical one. The transparency of our planning process is related to the fact that we have a lot of information systems. In the 1980s and early 1990s, system planning was in charge of essentially all of the capital-intensive expenditures for the company. Generation projects, transmission projects, everything was pretty much decided within the department. Often, we had to provide purpose and necessity statements for those various investments, and why we picked or vetoed a certain place. Most of

the time, the statements boiled down to, "because we said so." To prove that, the person who was the manager of system planning became the CEO, the next person who was manager became the COO and the two vice presidents under him were also former managers of system planning. System planning was tremendously influential in other companies within PJM because that's just the way it was. The bottom line was that nobody messed with us because we could wipe out a project with a signature. That type of thinking lasted roughly into the mid-1990s, when restructuring of PJM began. Out of that came a new planning process, which also has evolved, and I'm sure will continue to evolve.

The process itself is open, and allows for input from a lot of interested parties. We coordinate expansion plans across a number of multiple transmission systems. The addition of PJM West will add another. The expansion plans look at all needs of the system, including outside influences. PJM wants to develop the most effective and efficient transmission system for the region. When we get done with this work, it's also important that we deliver a reliable system. Many a system operator will tell you that in spite of everything that's happened out there in the world, nobody's told them yet that it's okay for the lights to go out.

The best way to picture the PJM planning process is a triangle. The bottom is the documented reliability criteria that have served for a long time, the approved tariff and agreements that have been developed over time and have evolved along with everything else. The real heart and meat of the regional transmission process is all of the evaluations of the various things that may be developed within it. The things that we use to determine whether in fact we're meeting the reliability criteria and how we're doing with the evaluation of the things at the top of the triangle we've

done for some time, but some have been added.

We have an ongoing and annual reliability assessment to determine if the transmission system is meeting the reliability criteria. We also assess the system for adequacy: is it capable of delivering energy to load centers under a variety of different conditions? Long-term transmission service requests have a tremendous impact on the use of the system and on the generation and other projects that are being developed. Long-term service has certain rights to use the system that have to be balanced against the rights of generation projects and other transmission projects.

Projects that are recommended by the existing owners of the system need to be evaluated. We look at operational and economic performance. We have a generator interconnection process that looks at all of the generator projects that come to us. Our generator queue has evaluated about 260 projects over the last three years. Obviously, not all of them are going in.

Our most recent addition is merchant transmission projects. We have several that have been announced and a couple that are in development stages. A very important piece is our transmission expansion advisory committee that meets twice a year. The concept is to get a lot of different people in the room. We go through what we have analyzed and we put the needs up on the board. We have some recommended improvements, but essentially, we're looking for some input from the various stakeholders who come to these meetings. At the last meeting, there were over a hundred people. We had fuel suppliers, particularly from the gas industry, who had some very interesting input into the transmission planning aspect. We've got generation developers, state regulators and consumer advocates. Those folks have a lot of interest in what

we're doing and how we're doing it. Obviously we have other meetings with them as well.

We try not to focus on any one area of solutions. Hopefully, with the correct price signals, with the correct pricing of transmission, we're getting strategically sited generation projects. We're seeing a lot of interest, particularly in the large industrial and some of the larger commercial customers who are getting involved in some type of distributed resources. We've also had interest - some of it stimulated by the states - for distributed resource projects that are primarily renewable resource projects. We've just put our third wind farm in Pennsylvania into service. A number of utilities have demand side or load management-type projects. These play a significant role in the planning process and they are a challenge for the planners because they do require a little different look at things. We're very used to looking at generation, but load solutions are a little new and it takes a bit of time for us to develop the tools.

Finally, there are traditional expansion solutions, advanced technologies, DC transmission and other things yet to come. We've had presentations on a number of magnetic storage devices, too. We're trying very hard to grab all those solutions and look at all of them as a package.

How do we measure the success of the process? Our most important measure is the reliable transmission system. In July 1999 and August 2001 we pushed the system almost to its limits, when we had high loads over a period of time. The system has held up well. We feel that we have planned a reliable system.

I think some of the more important parts and some of the things again that evolved out of work done in 1996-97 and what continues to evolve as we move forward are the things we're doing to broaden our

scope. We need a large range of stakeholder input. We need to see what others have to say. Hopefully, we take a look at all of the possible solutions and balance the considerations across all the potential solutions and all the potential drivers.

Planners were not known for being flexible when I was a planner. But I think planners have become more flexible out of necessity. We emphasize strongly to our engineers that we cannot just rely on what we've known for a long time, but we need to look at new tools and new methods for analysis. A couple of our system planners have taken existing tools and developed front-end capability that processes solutions faster. It's very interesting that they've taken such an interest in this whole concept of flexibility of tools.

You know, things change at a tremendous rate. Over the last couple of weeks, we've had probably twelve generation projects withdraw from the queue for a variety of reasons. Two are in pretty key locations. Now we have to retool our plan and say well, that generation is not going to be there. Do we need other solutions? Do we need a way to take up the space where that generation came out? So we need to be flexible and accommodating of the rapid changes going on in the industry.

Our process is very results oriented. We do not write huge papers that go through all the theory behind what we do. We tend to let the results speak for themselves. We focus on getting the solutions evaluated and in place because, typically, the solutions that we're coming up with are long term and need to be developed quickly. Our horizon is long.

We've heard from others that our process is very transparent. We provide enough information. We provide enough stuff about what we do, how we do it and why we're doing it the way we do so that most people feel fairly comfortable. They may

not totally agree with every aspect, but they understand what the rules are and they can work within them to develop projects and to move forward. They also have the ability through committee structures and through the transmission expansion advisory committee to suggest changes, to bring changes through the committee process and those can evolve into an ongoing update to the planning process.

Our first regional transmission plan was approved by the PJM board on August 1, 2000. The plan is still in effect. Currently there are about 300 million dollars of transmission infrastructure improvements, including both attachment facilities for generators and also network facilities. There are about 39 projects that are still active. The plan is very fluid because there have been a number of changes since August. The second plan was approved on June 5, 2001: roughly, an additional 400 million dollars in transmission infrastructure improvements and 43 additional generation projects. Again, that has changed since June, but that's what the process is about: responding to changes, being fluid and being able to handle the types of things that come to PJM.

Discussion

Question: Does PJM's plan compel people to then build for things that are in the plan? What happens if the things that you want aren't built?

Response: PJM identifies the need and does a recommended reinforcement. At that point, others can suggest other types of reinforcements. But if a reinforcement is not built to take care of what we need, we identify it. We have the ability within the agreements to essentially compel a transmission owner to put the reinforcement in.

Question: Can the two plans' numbers be added together, or is one an update of the other?

Response: They can be added together.

Question: TransEnergie has pursued projects where there's a clear cost differential between the two ends of the line, and there is a chance to put a DC or other form of controlled link between them. Where do you come down on the prospects for merchant construction of AC grid enhancements that need to be built to relieve congestion, where you're not going to be able to control access to the link? What forms of financing make sense? Can this be done, for example, based on the traditional regulated cost of service or do we have to devise a new form of cost compensation?

Response: Under appropriately structured FTRs, you can do merchant transmission investments in a free-flowing network. I'm not sure we're there yet in terms of the PJM and New York frameworks. We need several enhancements, and to make sure that we have a longer term and duration for those rights. I would also look for optionality, the concept of auction revenue rights that's being talked about in New England, and a mechanism to capture the reliability value of that transmission enhancement, that intra-control area grid enhancement. Right now the FTR gives you the price differential on an energy basis. With that, targeted transmission enhancement also provides reliability benefits. They can be in the form of a reduced ICAP requirement and other reliability-type enhancements. I'm assuming that you have a capacity market; if it were an energy-only market, you wouldn't have this issue. I would also advocate for some incorporation of the capacity reliability value, making sure that the people who support the costs of that transmission project receive that value.

Question: Isn't there a case to be made that there are really two competitions, one for the implementation of ideas and the other for improving the transmission network, and who can come up with the best? And their value is separated. What happens if a project only makes sense in conjunction with another project and one of them doesn't happen? In your framework, don't you need the ability somehow to put limits on what else can be built so that what you have proposed is not undercut later, which is what happened in Australia?

Response: I'm not sure that you can really separate competition for ideas in financing. An integrated solution is needed and it needs to be evaluated as a package. From a general perspective, you can't foreclose anyone from going forward. You may want to foreclose a socialized type of cost recovery for a particular project if it does not prove to be the perfect solution. I don't really see this as exclusionary to anybody willing to risk his or her own money.

Response: The pleasure of socialized cost recovery happens to some extent to the transmission on a regulated basis in Australia, because every five years when the regulatory set comes around, the regulated transmission companies responsible for planning have a fresh look at whether the investments made were efficient and the assets can be written down. That happens in principle; the practice is more difficult.

Response: It's important that all of the load solutions, generation, transmission, merchant projects and other drivers are looked at as an integrated system. You're looking at the same transmission system in protecting rights of the various people who use it, so the integrated nature of planning needs to be preserved.

Question: If you're going to support a system like you are proposing, you also

need pricing reform at the FERC level. I can conceive of a situation where, if you build a merchant facility, you're going to auction off the FTRs to people who would want to use that facility. On the other hand, if someone plays a game of chicken and says, "It's in the plan," and the provider of last resort, the transmission owner has to build it and it's going to be rolled in, and once it's built there are no FTRs, why would anyone pay for something that under the present pricing policy is going to have to be built and rolled in? At the same time, don't you have to deal with transmission pricing so that you put both merchant transmission and the financier of last resort transmission on the same basis?

Response: Assuming that what you mean by transmission pricing is a bias toward socialization, and basically not have any type of cost causation?

Response: I'm describing what I understand to be the policy of the FERC as far as allocation of transmission costs.

Response: That may have worked in Texas, but it certainly doesn't work in New England. If you're saying if we have a system as you describe, then I generally agree with you. You would have to make sure that these are treated on an equal footing.

Comment: It's clearer how the DC transmission gets handled because it is controllable. The AC system is more difficult to figure how to price a merchant AC transmission, at least right now.

Comment: But incremental transmission should create incremental FTR and that would be a reasonable way to do it. The comparability between a provider of last resort, the incumbent transmission owner that must build, and under present policy, almost always has to roll it in, versus the ability to auction off the FTRs and have it as a user is how it is financed. FTRs are

great if whoever builds it is treated the same. That is a change that is necessary to get everyone to buy into this.

Question: With respect to PJM's role in economic enhancements, as opposed to reliability enhancements, and in light of your ability to compel owners to build and FERC's orders to encourage you to emphasize the economic expansion more, do you see a role of compelling transmission owners in your process to build economic enhancements, or do you see that coming out to the market?

Response: We're about to start a stakeholder process to look at how to handle economic enhancements. We're looking for some broad input. How we identify an economic or transmission congestion problem may be satisfied through an economic way. If it doesn't get satisfied, does a congestion problem at some point become a reliability problem?

Response: We've grappled with the difference between economics and reliability in Australia. We've got a project that services the southern part of New South Wales on a reliability basis, but also enhances the interconnection with Victoria. Many projects are like that. If you want to maximize the benefits, you often integrate the two.

Comment: It seems to me that when the market fails, there has to be a backstop brought there by regulators and politicians and the full weight of the law. My concern is that generation competing against transmission is very difficult to compare for long-term projects. I'm concerned about the process being very politicized and that the backstop then overwhelms the market commitment of capital because everyone's waiting around for a subsidy to come out of the regulated auction. If one were given full opportunity to enter for merchant transmission, wouldn't you be willing to give up the option or the

opportunity to compete for these regulated investments?

Response: My goal is to inject competition into that last step. What puzzles me is why transmission owners who are in such an advantageous position to win a solicitation seem to be terrified. Why do we need to make an assumption that we can't have entities compete for that backstop solution? It's not good enough to say it's too hard to set up a framework. There are some big issues and this isn't as easy as I'm painting it, but let me emphasize that we are talking about a backstop process here. If we get the prices right, if we set up the markets right, I hope never to use the solicitation process. This is a backstop process that we propose to remedy any market failures out there. I hope it is simply a process that remedies situations that cannot be solved by fixing the markets first.

Comment: One of the ways you can have market failure is you have a bad market design. The first choice would be to fix it. If you do that, this distinction of where you have necessary reliability investments that are uneconomic vanishes because you've gotten the prices right. But you could have economic investments that are the free-riding problem for which you need the backstop. The characteristic of those is that they've got to be big enough to make a material difference in the prices. The market can solve this problem and FTRs are going to be equal with the margins or the cost of investment. The only things you have to look at as possible competition in the backstop are other really big lumpy investments that can't come in small sizes. This answers the question about subsidization because should small demand, disbursed demand, load demand, quick projects, be included in the process? No, because if they're a solution to the problem, it's evidence that there's no market failure. The fact that they're not being done given the prices that you have just means that it's not

economic and it's not a good idea in the first place. When you get to the backstop requirement, there might be other big, lumpy backstop investments, but I bet that's going to be a pretty rare circumstance. You might want to allow them to come in. But I think it's a very narrow class of things, once you keep remembering that it's only for places where you have market failure, because a lot of the stuff is politically contentious also has the characteristic of being collectively large, but individually small. If it's small, there's no market problem.

Response: Given that FERC is now taking over jurisdiction of all transmission through the RTO process, it's really important that we think carefully about how transmission gets built on something other than on a theoretical basis. Building transmission is a complicated process, with a timeline that is not easily amenable to an RFP. It starts with a detailed computer analysis and trying to come up with solutions, followed by a careful evaluation of the system, looking at what right of way exists, whether it can be expanded, whether the rights on the right of way are amenable to being used for different things, whether there's space in substations, whether one route is better than another, whether to go underground or over-ground. Every one involves an economic tradeoff with your maximum project.

Then when you decide what you think the projects wants to be, you do your detailed analysis. You've got to go out and deal with the landowners, talk to the mayors of the towns and cities that you're going to cross. You end up building something different than you thought you were when you did your planning back home. When you've done all your work which takes a lot of time and money, you go into the siting process, and everybody runs in and says, "No, no, no, don't build near me." You have to move your line or open up your process again to look at the

alternatives to see if maybe you are better off from a siting standpoint. Often, you come out with a transmission line that's very different and has a very different cost profile.

When you've finally gotten approval of a site, you start your detailed engineering work. For the first time you have a decent cost estimate of the project. And when you build it, you find out that you thought you could get through such and such a location, but there's a swamp, a cemetery or a landowner who's fighting you and you make change orders and the cost changes.

A simplifying assumption that we're just going to have RFPs and we'll let the winning bidder build the line or whatever other solution is the way to do this ignores the reality of what it takes to build most transmission projects. We need a policy that's at the same level of sophistication of the requirement to build. I see a real mismatch between the two. I'm not sure I understand that you only need transmission when there's a market failure. I am saying that we need to make sure that we incentivize the right people to build and don't make it harder for them by calling them bad names like incumbents.

Response: You've got the problem absolutely right. Reality does have to match policy.

Comment: From a policy standpoint, I'm troubled with the idea that we'll let the projects that look economically very favorable go out to bidders. And the projects that require years of work and a lot of political capital and getting every landowner angry at you end up going to the traditional utility. That's cherry picking, that's not a market.

Question: Are you saying there shouldn't be a merchant transmission investment?

Response: If they're going to participate in the merchant investment, you should have an obligation to build like everyone else, come in and take on the pleasures of transmission responsibility, but don't cherry pick.

Comment: Isn't that a funding issue though, not really who builds and who takes the risk? Many of the incumbents want the same cost recovery treatment as the merchants. If they're going to be subject to competition, that's fine, but I don't think the rules are the same right now.

Question: Is the reference network being used for PJM or elsewhere to set benchmarks for optimization or is it brand new?

Response: Not too new. You may be aware that in the UK they have it among locationally differentiated investment pricing, but the actual price differentials are nowhere near what they ought to be. And while a cynical view could be that the transmission company would not necessarily like to see very large price differentials because in the UK there was a possibility of gas transmission getting into the business of transporting gas from the north to the south, in which case the transmission would lose out as a transporter.

Comment: If you can export that kind of methodology to institutions like PJM or an ISO, it would be a valuable additional tool for transmission, especially if an LMP doesn't always suggest the kinds of enhancements or changes that optimize transmission systems.

Comment: Before I got into transmission, I spent nine years building a nuclear power plant. One of my assistants made the observation that if they were easier to build, there'd be more of them. I think we've made the same observation about transmission. When you look at the

competing supply-demand sides and transmission solutions and the problems on the grid, probably the supply and demand sides are easier and can solve the granular problems that surface. Often it's easier to build a generating station than transmission. The payback periods typically, that the project developers use are much less than the cost recovery for transmission. Where you have markets existing, the supply and demand sides will end up winning out over transmission solutions, be they merchant or economic solutions, in most cases. The problem is that a lack of transmission is often a disguise for a lack of proper pricing in the marketplace. I applaud FERC for pushing RTOs and proper markets forward, but it's only a very little part of the US where we currently have those pricing signals. I conclude that to try to address economic transmission before you have the requisite pricing signals in place is an exercise doomed to disaster. Do we need to get the markets right first before we make what could be flawed judgments about economic transmission?

Response: For the most part, the supply-side option depends on energy for its revenue. The transmission company in the whole equation is the first piece that's going to depend entirely on FTRs in a market situation. FTRs have been in practice for two or three years, and have quite a different characteristic in terms of your revenue streams. It's a new pricing regime. There are a lot of uncertainties in putting it into practice.

Comment: In our system, the bulk power system represents two percent. In another system it might be five percent. In Chicago, it's five percent of retail rates. If you have a planning process and decide that you need a line, tell the incumbent and we'll build it at cost. We'll roll it into rates, get FERC approval, earn a regulated return and it's part of the infrastructure. We ought to have a robust grid. The one built up over the last fifty years wasn't

designed to serve the markets that are evolving, so we need to expand it. If the ISO or RTO says that transmission is needed somewhere in the region, you build it under cost-of-service regulation. A lot of the issues around building transmission are environmental and NIMBY. If you have to live in the territory where you're building the transmission, you're going to spend political capital.

Comment: It may not be a market-based solution, but it's such a small smidge of the total cost of what we're trying to do. Leave that piece regulated. As long as you have the people who are making the decision as to what is needed and you have a really independent operator, what's the problem?

Comment: In Australia, we've got a real strung-out system. It's seven percent of the total cost. Compare that with injecting the competition benefits into the energy market generally, and it's a second or third order effect.

Question: What about the congestion costs?

Response: Congestion costs ought to go down when you build new transmission.

Comment: It's a lot more than five percent if you look at the costs of getting across the interface.

Question: When you select a non-traditional supplier, what are the obligations to complete a transmission project in a given time frame, and what penalties accrue for failing to meet that obligation? It's pretty clear what happens in a traditional, regulated utility context. There's a loss to market participants for someone who commits to develop and after two years of encountering NIMBY or other factors, throws in the towel or turns it back to the provider of last resort.

Response: In Australia, if it's a project that's been put on the books, who's to say this is not going anywhere and we're back to the drawing board? Nothing.

Comment: There should be indemnification. There should be liquidated damages. This is a contract and if you don't perform, there should be penalties.

Response: Right now, PJM doesn't have any actual commitments from non-traditional suppliers of transmission. For generation, essentially there is no real penalty; they either build or not. Penalties are probably more related to people who may or may not have contracts with them for the delivery of the energy.

Comment: Here are two scenarios around the RTO identifying economic upgrades. In scenario A, you have an RTO completely independent of asset ownership that's now identifying economic upgrades. What would the liability be on the RTO? In scenario B, the RTO now owns transmission assets.

Response: Regardless of the ownership issue, the toughest part about the economic upgrades is that the system and its economics are changing fairly rapidly. That's one of the biggest questions PJM has about identifying economic transmission. By the time you do the evaluation and decide this is now an economic upgrade that needs to be made, the transmission project could take seven years to build. Theoretically, the system economics have changed several times. Whether the RTO or ISO owns facilities, the tough part is that you identify an economic upgrade at a point in time and make a recommendation, and then down the road, that condition may very well change, based on more generation coming in, different load-side things that have happened. How you assure that you in fact implement the right solution is very difficult to do with something that takes so

long to build. That is one reason why at this point, PJM only does reliability recommendations.

Question: You mentioned two points that are the basis for your practical solution to the backstop: predetermined criteria for planning and the competitive solicitation. PJM's process is results-oriented, fluid, flexible and most of all, the integrated nature of planning needs to be preserved. Are you talking the same thing? Are those criteria for planning or is PJM doing a broad-brush look outside the bounds of reliability-needed transmission that takes into account the best generation solution, the best economic solution for transmission, the best solution for congestion? Are you going beyond the confines of the narrow question that has to be the focus if you're going to have effective competition and merchant projects for transmission? Also, what is the Australian perspective?

Response: PJM makes two recommendations. When we do a reliability assessment and we see a need for transmission, we make a recommended solution for reliability-based need for transmission. The integrated nature is that generation and merchant transmission projects get in the queue. Transmission and long-term transmission service requests are the same, and even to a certain extent, load-based additions. We can't do reliability-based planning and not take into account the fact that there are other things that are trying to use the same transmission system that we're looking at. The other recommendation is that when we get generation or other types of uses of the transmission system, we will identify needs and make recommendations on for, instance, the projects required to accommodate a generator, or that may be required to accommodate a merchant transmission project.

Response: In Australia, while we've had more experiences of this than probably

most people because of the projects that are on the ground or in the pipeline, very quickly we're seeing some very serious issues. We have a regulatory test that attempts to be a cross-benefit analysis. That is already the subject of an appeal to our tribunal. Not one single regulated project of an interconnected nature has actually gotten through that test. It's very experimental, even with well-set-out, predetermined criteria. In Vencor, the one model that seems to be heading down the path, there isn't a lot of capital project development going on in Victoria, so it's not really being tested on any major project. Most of their work relates to reliability projects because they are a state-based organization. They're not getting involved in the interconnect projects. As experienced as we are, we're still very experimental.

Comment: Should the government use its regulatory authority to prevent a merchant from building a transmission line that competes with Rainbow Valley? My answer would be no as long as the merchant company is prepared to do it with its own money and take the risk. Should the government be able to compel Sempra not to build a transmission line that competes with Rainbow Valley if Sempra wants to spend its own money? My answer is that they should also be allowed to do merchant investment. When neither wants to do it because they can't capture the benefits in the marketplace and they don't want to risk their own money, then you get around to the backstop choice and compulsion takes the role of making people pay who don't want to pay for it, where you send the bill to the customer and say, "You pay for this transmission line that's going to be built." Should the government use its authority to do that? I would say yes, if it can pass certain tests like the market failure test. It's a standard regulatory problem if both entities want to build. Regulators would have to evaluate and choose. I wouldn't say that there has to be an absolute rule that the only people

to take on the obligated service is Sempra in this case. If neither wants to do it, should we order the merchant company to do it? I think the problem is not that Sempra doesn't want to do it. They just want to get the approval and then use the compulsion of government to make people pay for it.

Comment: The issue is that there is a lot of hidden risk and cost to building transmission. In the real world, it's so complex and iterative process that it's really hard to design a workable process that allows for competition.

Comment: The political capital that a company takes to build a line is huge and oftentimes at the expense of more lucrative businesses.

Comment: My concern is the demand and supply options coming in under the regulatory backstop, simply waiting for those subsidies to be doled out by a highly politicized process. The typical gas or combined cycle turbine says, "Don't build that \$300 million transmission project. Give me 100 million and I'll put in a combined cycle." It's apples and oranges comparing the two, since they're saying they'll come in for one third of the price. If you agree that they're supposed to feed off the market and when we're only dealing with market failure, then those options shouldn't be able to compete to do the backstop.

Question: If they're coming in at one-third the price, isn't that good for customers?

Response: They're coming in at one third, plus they're getting all the upside for the length of the plant. They get all the price volatility and a nice subsidy, whereas the transmission that they're supposedly competing against is locked into a regulated return. This whole thing is more tractable if you use the granularity argument that the only thing you're doing

here is that there's been a market failure and go to those lumpy projects.

Response: Economies of scale is basically the whole problem of the transmission market thing. If you're going to do a lot of deep bottle necking on the existing system, you might not have the large plant problem. But transmission is never worth what you pay for it. The prices aren't there after you build it and it seems to me that problem may persist. If we just have a regulatory backstop and only use it when nobody wants to build anything, we're liable to wind up with a system that encourages small, sub-optimal projects and misses the big ones that might actually be worth doing. If a merchant would like to build a line here because it thinks it is profitable, I'm not sure how the state then says, "If you do that, you have to build a line over here, too and take all the risks." If big transmission companies are taking on big projects and all the risk, then I guess they should be able to keep others from cherry picking. There might be some big projects. Maybe you have to do it on a regulated basis. Should a regulated entity be allowed to get into the merchant business and do some things on an unregulated basis, when it's also probably doing the planning and a lot of other things? I think that is problematic. The reason we have regulated monopolies is because there are natural monopolies that do things that we can only get done with the regulated monopoly and it's their job, not to go out and compete for things that others want to do and make an entrepreneurial problem.

Comment: One can argue that a generator-based project is more complex to build and operate than transmission. In the context of a backstop regulation for example, in the UK there is a belief that there will always be enough generation to meet the demand. If there isn't, somebody will bid on a project.

Response: In some cases it's easier to build transmission than generators. Transmission is a linear project and you have a multiplicity of landowners and interests along the way that could very well result in a more difficult siting process than a single-point facility. My opinion is that we don't need a backstop. However, we are faced with a political climate that is requiring some level of system planning. We need a process that is as market friendly as possible.

Comment: There won't be two Valley to Rainbow transmission lines because it isn't necessary. The route runs through a developing residential area of tremendous value. It makes no social sense to destroy hundreds of millions of dollars worth of property value. Political reasons are going to be a barrier. If you do invite a merchant to come in, you have to give it eminent domain authority because it isn't going to be possible to build without that. You will have a delegation of government authority that implies that there has to be some political input into the process, unless we're just going to give up governmental authority to private entrepreneurs. The alternative to the Valley line is much more San Diego-based generation. The California Energy Commission has to take into consideration the air quality implications of its siting decisions.

Question: Would it pay to put it underground?

Response: It would pay the property owners to have somebody else pay to underground it. Maybe there are new technologies, but this is 60 or 100 miles.

Comment: This is a situation where nobody else wants to build it and you need a regulated entity to do it. But that doesn't imply that there should be a rule that nobody else should be allowed to do it.

Response: Once a line is built, if it's the only game in town, it's able to collect

monopoly rents. Are we going to hand out these franchises?

Comment: Do you prevent someone from competing with a merchant builder after it's built a line?

Comment: The point of the backstop is that when there are some situations where there's no practical alternative to having the regulated entity do it, then it should do it. But it doesn't mean that you should then have a rule that nobody else can come in and do it.

Question: Money to pay for such a project does come from somewhere and there is the potential for monopoly rents. So customers will pay one way or another. Should there be a point of comparison between what one side is prepared to put on the table and the regulated alternative on a cost-benefit analysis?

Response: The theory of markets and dynamic efficiency is that people say, "Look at the enormous profit I can make if I build something." They make a lot of money for a while and then someone else comes in and competes and it goes down over time. You can't have a market system in which you say you're going to enter and if you fail, you fail, and if you do not, you just make the regulated rate of return. If a merchant is prepared, willing to take the risk, builds a line that doesn't need eminent domain and we don't prevent others from competing with the merchant, I'd let it extract as much money as it can get.

Comment: There are elements of this discussion that remind me of the debate with respect to putting services like billing and metering out for competitive bid. In that discussion, people often confuse outsourcing with setting up a market and letting it work. I use the term to mean independent buyers and sellers who come together with private transactions to their mutual benefit. If you want to build a merchant line and you can get somebody to pay for it, you ought to be able to do that. If a regulated entity wants to do it and can get somebody to pay and risk its own money, that's also fine. But when nobody wants to build the line on its own, you have by definition a market failure case, which is why you need some sort of regulated monopoly to begin with. The notion of being allowed to bid, or allowing an independent third party to bid seems strange because then the question is whether the utility should outsource, build the line with its own labor, or if someone other than the utility should be the project manager. The IPP situation of forcing utilities in New York to go to all-source bidding unleashed a monster that could not be shut off. Outsourcing to a third party is not always better because you get locked into inflexible contracts, especially with a very complex project that you know will change as you go through it.

Comment: There should be an opportunity for other innovative structures to bid, perhaps on a project finance basis. I'm not sure that just having a monopoly over ownership truly brings those innovations to the table.

Session Three. Slicing and Dicing Carrots and Stick

Embedded in the long-running debate about ISOs versus transcos is the question of who performs what functions. How are grid/market functions to be carried out? What efficiency gains, if any, are there from combining functions? What biases, if any, are embedded in transcos or ISOs? What lessons can be derived from the California experience of bifurcation between the ISO and the power exchange? Is it inherently better for a for-profit or not-for-profit entity to make certain critical decisions? What are the respective incentives and liabilities for transcos and ISOs in performing their functions? Are some of the incentives for

transcos perverse, as some have suggested? Are a transco's potential liabilities of sufficient gravity to offset any perverse incentives? Are there meaningful incentives and liabilities for a not-for-profit ISO? What are the consequences of inadequate performance for transcos and ISOs?

Speaker One

If we don't allow fully functioning transmission companies to be established, we won't get to a viable solution for an efficient, competitive electricity market in the US. The vision has two aspects. One is a few big wholesale electricity markets with common rules that function across very wide areas. The order on MISO and the Alliance at least takes us in that direction. On transmission, we're aiming for an independent, big efficient, well-funded system. Congestion is the killer of liquidity in the wholesale markets, just from the very nature of this product. There are a limited number of generating sets competing at the margin. You not only create local monopolies, but you take generating units out of the wholesale market because they're pursuing that local monopoly. So low levels of congestion take on significance in a liberalized market where generation is competing.

I don't believe that ISOs sitting on top of vertically integrated companies are a solution. The Midwest ISO market will be 170 gigawatts. What do we expect MISO to do in terms of running transmission? There's nowhere else in the world that a system of that size is run in a single tier. If the ISO is really going to be that big running those excellent, big wholesale markets, it is never going to be in control of those transmission assets. Who is really going to be opening and closing the circuit breakers? Who's going to be determining maintenance policy? It'll be the vertically integrated companies that are still running the transmission.

ISOs deliver huge value. Open access to big wholesale markets is their core skill. But you need a professional transmission organization seeking to invest, seeking to

sweat those assets, seeking to put the last megawatt through those assets. My expertise is in driving transmission assets to their safe limits without a sophisticated pricing model. In the UK, congestion has dropped from five hundred million dollars down to twenty. Motivate transmission companies to provide a flexible grid as the generation market becomes more liberalized. Play in multiple markets. And when a generator identifies an opportunity, get it connected quickly.

But wholesale markets will not work without good transport. You can have a fantastically good wholesale market for coal and buy excellent cheap coal in Australia. If you haven't got the ships, the wholesale market is of no value. Generally, transcos don't run energy markets around the world. It's not a core skill and it's a good argument to say a more public-spirited entity should do so. Similarly, don't ask ISOs to do what isn't a core skill for them.

In the transition about what we should do to mitigate the perceived problems in putting together properly functioning transmission companies, there are two options. The first is to give the transmission functions to the ISO. I think the logic runs that transmission continues to be a Cinderella function in the US. There will be poor investment and not much innovation that will spiral into declining values of transmission and then no divestiture will occur. ISOs trying to control very large chunks of transmission that are still in vertically integrated company hands will stop the wholesale market from functioning properly. Some of FERC's thinking is to take out the functions we're worried about and as

transmission gets fully divested, our independence becomes solved and we can pull those functions back into transmission. Once functions are put into organizations, often newly created, it is the devil's own job to get those functions pulled back out. Once these functions are gone, you won't have the opportunity of recreating viable transmission companies.

The second option is to create fully functioning ITCs in the short term that will then roll through into the long term. Let companies that really want to create value for customers come into play. That will allow the value of transmission to rise. Vertically integrated companies would divest and that will lead to a working wholesale market.

The move to have standard market design will almost certainly mitigate a lot of the concerns that are being raised, for example, if ATC calculations are prescribed as to how they would be done. Quasi-regulatory oversight is part of the business model in the short term. Super-regional aspects should cover tariff construction, regional planning, security coordination and a single OASIS. But I believe that an ITC must be free to do the detailed, hands-on control of assets and come forward with value-enhancing propositions for investing in the transmission system. There are concerns about whether transmission companies will favor their own transmission for up generation. My plea, however, is not to take vital functions out. Let's find a way to make this work in the short term that can keep alive the vision of fully functioning transmission companies in the future in partnership with good wholesale markets.

Question: Should transcos do markets or not?

Response: No. Markets should be in the public-spirited entity.

Speaker Two

I look at this slicing and dicing from an ISO perspective, since a lot of my time has been working from that perspective. I believe there is a lot that has to be seen about how this is all going to shake out. Something I find more confusing than helpful is the plethora of terms in the FERC filings that seem to me to impede, rather than help the discourse. We have ITCs, transcos, gridcos, independent, the international transmission company that spun off where Detroit Edison calls itself a wireco, RTOs, ISOs, IMAs, binaries and hybrids.

We need to focus on the transmission ownership function, really the creation and maintenance of the largely fixed assets, and then on a separate set of service issues, the system operations, the performances of services using those assets and then the slicing and dicing issues address the extent to which you combine the two functions.

You can start from a set of functions that are fairly conceptually distinct. How do you combine those without violating the law? The first principle to keep in mind is the potential substitution of generation and transmission and the inevitable market interest of transmission. I have a hard time overcoming the concern that the involvement in any function, any service relating to the use of transmission assets that could result in a tilting of the playing field toward transmission is indeed problematic, and suggests that there may be well be a role for the ISOs or some independent entity that's really going to have the ultimate responsibility for operating assets.

The New York ISO and PJM models are working well and have a form of ISO with transmission ownership members today. New York is particularly instructive because transmission owners are in large measure, independent in the sense that

they divested most if not all of their generation. Is there any different set of conclusions to come to if one combines some of those owners into larger entities or puts them into a different regional scope? The interrelationship of grid and market operation is hard to escape. Operating the transmission system at least in New York/PJM means you run the moving generation up and down. That's the important piece. The profit versus not-for-profit distinction is somewhat of a red herring that doesn't really advance the debate. The concerns that might be troublesome with a for-profit transmission owner operating market-related functions would arise with a not-for-profit owner just as much. A for-profit model certainly could apply to ISOs.

I think PJM is nominally a for-profit entity. Even in an ISO where the entity is legally a not-for-profit, one might envision a world in which the operating functions would be put out for competitive bid by a for-profit entity. The incentive argument provides the right incentives to get the right results for the service function that might be in the hands of the ISO as well or as preferable to the transco, particularly if one can achieve the result with the right incentives without being concerned about the conflict of interest that might accompany transmission ownership.

What are the true efficiencies of the transco model? Compare the current ownership situation in New York with a regional transco model. Articulating the real market benefits of the difference would be incumbent in advancing the debate from the transco side. Is the attraction of capital enhancement in the transco coming from real efficiencies and real market benefits or from an ability potentially to tilt the playing field toward transmission in a way that's not related to efficient market outcomes? And is a regional transco the optimal entity to deal with the regulatory hurdles to

transmission, and is the real problem again more regulatory than financial?

It seems to me that transmission investment versus operational efficiency is not really addressed by PBRs. The incentives might well go to the service provider in a variety of guises, and might apply as well to an ISO.

The following quote from a FERC filing raises more questions for me than answers: "There's no basis for the Commission to conclude that, as a general matter, regulated asset owners can no longer perform either of these functions." That suggests that we don't now operate in a market environment in a way that concerns arise that didn't arise earlier in the regulated asset owner model. The quote goes on: "It would be extremely dangerous, absent compelling evidence that the capital required to fund necessary transmission will be forthcoming, if independent transmission companies are barred from performing these functions." I wonder if that's just a rate of return issue, not again an argument that takes you necessarily toward a particular transco model. To the extent that investment decisions are being made before facilities are built, returns are built in to the financing model that doesn't depend on how those assets are subsequently used in a market function. Again, the argument perhaps doesn't take the transco model as far as its proponents might think.

Contrast this with the International Transmission Company formed by Detroit Edison in spinning off its assets. ITC identified three critical functions to be administered by the RTO: limited tariff control, the ability to establish new products, servicing and pricing for transmission in addition to a recourse rate for RTO access to the system; maintenance and planning coordinated with the RTO having the final say. This is a useful list for identifying the core transco functions.

Finally, in this economy, it is certainly odd to separate ownership and control the way we do in the ISO model. I confess to some discomfort but I'm not sure how we get around it for now. I see some value in having a large, for-profit entity that's interested in transmission. You need somebody in the ISO collaborative and cooperative stakeholder process who is really interested in planning, siting and advocating and is willing to make market-driven grid investments when appropriate. It also is appropriate in some limited circumstances to have PBR and other incentives. You want a for-profit that will realize the benefits and respond to the incentives. An effective transmission entity can pursue the ancillary businesses that go with transmission. When the American Transmission Company as formed, fiber optics was a way to get additional value out of the system. For the purposes of this debate, my list of functions goes in the ISO column.

Question: How do conflicts within functions arise?

Response: The conflict of having an entity with a commercial interest in transmission making decisions might tend to favor a transmission outcome rather than a generator or other solutions.

Speaker Three

We are trying to unbundle a complex system that has thousands of functions. We're trying to put some in some boxes and some in others and people are losing sight of what's really going on and are getting tied up in words. We need to focus on the functions, then talk about what I call an ISO/gridco system and define a transco.

Critical to the electricity market is an efficient spot trading function, because things change so fast that no contract can keep up. You also need a real-time instantaneous dispatch process to keep the

wires from burning down and to make sure that demand equals supply within transmission constraints instantaneously. The two functions have to be so well integrated that they're almost the same thing and separating them is difficult. We give the functions the names of disco and gridco and retailco. In a competitive system they may be separate companies. The critical dispatch functions are done by the system operator that gathers information, tracks what's going on and tells people to respond. The spot market has to be closely integrated with that, as will the day-ahead market. While there are some practical reasons for integrating, it's not absolutely essential. There are also bilateral trading, separate power exchanges and so on. But it's important, I think, to make a real distinction between the trading that goes on in the market and the real-time coordination function that to be efficient, should be a market closely coordinated with the dispatch function.

My interpretation of an ISO/gridco system is that you integrate the system operation and the real-time market. Grid ownership should be separate from generation. The ISO operates the dispatch in a market base. The bid-based dispatch is a combination of a spot market and system operation, determined in a single integrated fashion, probably with a day-ahead market for unit commitment.

The grid owner physically controls and maintains its assets. If you want to call it a transco, you can, but the distinction that I've always made is that a transco provides transmission service. What's that? Engineers have convinced me that you provide service by coordinating the whole operation of the transmission system, by making generators do their various things, ancillary services and so on. The transmission service is provided by this combination of the real time dispatch and the real time spot market that uses the grid assets to deliver electricity.

In such a system, the ISO could be for profit or could be a private company. It's a public regulated process that designs the dispatch and market processes the ISO uses, and probably leads to system planning efforts, solicitation processes, or certainly plays a big role. The entity that actually leads may be a separate transmission administrator or conceivably, the gridco. But probably the ISO ought to be doing that. It is critical that they operate a dispatch market process on an integrated basis. The gridco, more than one, are for-profit companies that own and operate the grid, in effect, under a lease with the ISO. They provide the assets just as a building owner would provide an office building for its tenants to do whatever they want and pay the rent, while the owner keeps the lights on and the carpets clean. The gridcos have some PBR incentives to operate efficiently. If they have ideas on how to improve planning, they can say so and they exchange information.

But the gridcos do not unilaterally plan or invest in the grid and its assets. Perhaps they compete in ISO-run solicitations, as long as the decisions about what to do are made by somebody separate. Separate entities provide checks and balances.

A transco is grid ownership plus system operations. Own the assets, turn them on, provide ancillary services, balance, run the system, but do not operate any markets. System operation means turning on switches when somebody from the market tells you. Making decisions based on some dispatch algorithm process is different. The definition I use is that the transco actually runs the dispatch and owns the transmission separate from the market. But if the operator doesn't operate even a real-time market, how does it manage real-time operations? How are imbalances and congestion priced? How are transmission rights defined and administered? The integration of the spot market with dispatch is the answer.

Most transco proposals assume or require some kind of non-market congestion management process, based on flowgates for example, so the system operator can determine the dispatch or balancing. Whatever advantages it may have in terms of incentives, it's a very bad idea, but it is a possible definition. Another definition is that the transco operates the grid, a real-time market and perhaps a day-ahead market all in one. Combining gridco and ISO functions would restore the critical integration between the system operator and the real-time market, but it would create other problems, like conflicts of interest in the operations planning and solicitation process. I don't know if transco proposals actually propose to put the real-time market within the transco. If you let the regulators, stakeholders and market participants become involved it dilutes the transco's incentives and accountability because it's got to do what the people who designed the market rules tell it. If you say that the transco can do it any way it pleases, then the market does things with tremendous power and that's probably not acceptable in the US. For example, a transco that owns the gridco and is the ISO monopolizes information and thus could favor the gridco over competitive investments. This will require someone to choose among the options and will require affiliated gridcos to be excluded from competitive solicitations. If you want a profitable gridco to invest, it is better to have a separate ISO.

Now what does separate mean?

PBR for for-profit transcos is very difficult. You can say you'll give them the right incentives to do the right things, but once you know what the right things are, what are the right incentives? In a quantifiable measure of a transco in the sense of owning and operating, it's hard to imagine maximizing throughput. The function of an electricity system is not to see how much power you can get running around the wires. It's to meet demand

efficiently and to minimize congestion and total cost. Saying, “Your job is to minimize this or maximize that,” leads to sub-optimization and problems. PBR is not easy when you get to long-term investment versus short-term operation. You could give an incentive to trade that off by telling the transco, “We’re going to give you a hundred billion dollars for the next 30 years and you’ve got to do everything because that’s all you get. If you can do it more efficiently, you get to keep the difference.”

In England and Wales, National Grid owns the grid and is the system operator. Until the new electricity trading arrangements were introduced in 2001, it combined the RTM and the system operation. It now operates the balancing mechanism under the new trading arrangements. This is largely successful from most perspectives and the PBRs have led to lower uplift in the pool, lower balancing costs, but perhaps at some cost in terms of sub-optimization. The point is to fore balancing costs out of the balancing mechanism back into sub-optimal pools run by individual market participants. The cost of keeping the portfolios in balance doesn’t show up in National Grid’s account, so we don’t know what they are and that’s a sub-optimization. Anyhow, it’s a model that works pretty well and we need to look at it.

For-profit transcos are supposed to be more efficient because they have a lot of assets at risk and thus are more sensitive to costs and profits. If they’re able to define performance-based formulas, that gives them a lot of up sides and they’re good at leveraging a monopoly to get unregulated profits. That’s not bad, but it’s not the same as maximizing efficiency.

ISOs are not easy to control or motivate. They can be given management and profit incentives and can be governed in the public interest for better or worse. If it

were easy to get efficient performance from monopolies, we wouldn’t be doing any of this.

Many people say, “Why exclude merchant transmission if you have good market signals. If people want to invest in transmission, let them.” I would add if it does not preclude efficient regulated options, because my main concern is the bias toward such investments. The larger things that really take advantage of economies of scale may never get on the table. How bad is that? I don’t know.

An ISO unaffiliated with any gridcos could fairly evaluate competing merchant proposals, decide when a regulated option is better, solicit regulated merchant investments and get the decision made in some reasonably efficient manner.

In my view if you don’t get the system operations and pricing right, nothing else is going to help much. If transco means that you’re going to have a non-market process for dispatch, balancing and congestion management and the other things that determine how people operate in real time, this is a very bad idea. Most of the alleged advantages of a for-profit transco are at best over-stated and could be attained at least as well with a gridco. We are trying to unbundle a big complex, integrated entity and there are no perfect solutions.

Speaker Four

We should just say yes to transcos. My model performs all the RTO functions, runs the market, owns the transmission grid, has system and transmission operations. The exception is that perhaps the market monitor should be independent. My understanding is that the generator and marketer interests feel very strongly about this, whether it’s an ISO or a transco, and want somebody independent because the ISO also has an interest in the market and needs some independent oversight.

The options are an ISO or an ISA. PJM is an example of an ISO that performs all the RTO functions but doesn't own or build transmission and has no ownership responsibilities. We shouldn't forget that in all the ISOs in the northeast, transmission owners perform significant operating functions, even though they have merchant interests and are vertically integrated.

A new model is in the southeast proposes contracting with a National Grid as the RTO. It wouldn't own transmission assets but would perform the operating functions from which it hopes to extract efficiencies.

There are also binary structures that have two or more entities performing RTO functions, one of which doesn't own assets. There are two such structures before FERC Any entity that performs RTO functions has to meet FERC's independence requirements.

The New England RTO binary structure has two entities that would be the RTO. One would be an ISO, responsible for operations and market administration. A separate for-profit ITC would own and build transmission and would be responsible for tariff transmission planning. The ISO would approve the transmission plan as a check on the ITC. This structure and split of functions were negotiated with ISO New England and approved by the board. It was designed to ensure that we would not balkanize the market.

The other structure comes from the Midwest RTO and RTO West. Underneath an over-arching ISO are one or more independent transmission companies. These ITCs may or may not perform some RTO functions related to transmission. MISO's Appendix I is the guidepost.

I have trouble having one or more ITCs not coextensive with the RTO taking on some RTO functions without balkanizing

the market, having more than one tariff. I suspect it is doable, but think it is up to the ITCs and ISOs to integrate the functions. The view of people who favor responsible binary structures is that the control area operation, real-time balancing, market administration and security coordination have to be in one entity. Switching, tagging and decisions about maintenance aren't performed by the ISOs today, but by transmission owners. There are efficiencies that can be brought to the marketplace by a properly incentivized independent transmission company or gridco performing transmission operations. If it can be integrated with the systems operation function, we ought to take advantage of that, particularly if there is congestion.

It is amazing to me that the transco proponents seem to have the burden of proof. There is no other industry I can think of where ownership and operation of important productive assets are separated. It's not done in gas or oil pipelines or in telecom. It has been a fairly radical idea in a capitalist economy and I think it's inherently inferior. The people who support the ISO concept have the burden of proof, not the transco proponents. That's the radical idea.

Most important, we need to attract equity capital for the transmission investments needed to handle a competitive market. You try to attract capital to a business where the people who supply the capital are supplying to entities that don't operate the business. Let's get the market right and we'll worry about transmission at some future time devalues transmission in an enormous way.

ISOs have little or no incentive to identify and invest in new technologies and operating measures. Ninety-five percent of the focus has been on system operations and market administration. The last decade focused on transmission to create the conditions for commoditizing electric

energy, not on transmission as a separate business. Now the focus must be on expansion and the place that the transmission business will occupy in the restructured industry.

What have been the barriers and arguments to transco formation? Public power is adamantly opposed. For example, in the southeast, they seem to have a lot of political sway over the debate. Some regulators are uncomfortable. Is this really the time to be creating yet one more profit-motivated entity to take more money out of the limited amount that's available before we find out how much consumers get to make? There's a natural tendency to go in the direction of the not-for-profit ISO model. I hope we can get beyond that, particularly if we believe that the incentives and profit motives that work for generators and retailers can work here. How many real transco proposals are we getting? Owners want to put something together, but they're not saying they're ready today to divest transmission. But if transcos don't form now, the concern is that transmission will continually be devalued so that there won't be a place to put transmission assets. And if you go down the ISO road, you're not going to move to transco very easily.

Often, the two wires functions in the electric industry use the same people and there is some reluctance to separate T&D because so much is done in a physical sense, such as O&M. The issue of whether transcos will act discriminatorily arises in discussions about transmission planning. However, if the process is open and inclusive and results in a written document that is subject to regulatory review, the opportunities for discrimination appear to be small. But let's assume that that the transco is able to slip in its favorite transmission project and the planning process is about to go to the siting phase. If the project is the wrong solution, or even if it is obviously the best, everybody

who thinks it's wrong will be there. Now let's assume you got approval through the siting process and you're at FERC. Customers could claim that it is imprudent and refuse to pay. A prudence investigation may reveal that there was a lower-cost solution that the transco refused to consider and now there will be hearings. I think that the natural checks that exist in our system of getting something built and into rate base completely obviate the argument that in the real world, a transco could act discriminatorily.

On the other hand, transcos will be able to marry their operating experience and an owner's detailed knowledge of the system in coming up with solutions. An ISO doesn't have that.

With the recent FERC orders and restructuring efforts, the separation of functions at the state level accelerated. As you know, once you unbundle, FERC has jurisdiction over transmission. There is no more state-run integrated resource planning. Transmission owners may not have any decisional role in transmission planning: the RTO has to do it. There is a ruling in New England that regulated, but not merchant, transmission expansion must be handled by an RTO competitive bid process. That is very problematical. You don't know what the project is and what it will cost until you're years into the siting process. This is the beginning of a policy debate. Under the current policies, we don't know who is supposed to build transmission. We've got to fix that.

I think merchant transmission has a small role. Most projects are not appropriate merchant solutions to the expansion problem we have now. Most people don't think that relying on the voluntary cooperation of transmission merchants will work. FERC could try to carve out a transmission owner's statutory obligation to build. We could decide that the RTO is a transco with a responsibility to both

operate and build. We could try to create strong, incentivized transmission companies and let them build the system.

Comment: In Texas, we recognized that there wasn't any way to get the public power entities to divest so we separated transmission operation from system operation from generation and from retail. Transmission owners can be affiliated with distribution companies but distribution companies cannot sell at retail: the wires business is nothing but a delivery business. The ISO was invested with a transmission planning coordination function that has been beneficial. It defines where the need is and sets out what the owners need to work on. The owners take that needs assessment to the PUC for approval. From the public's perspective, it takes the transmission investment decision out of the self-interest of the transmission company. The need has been defined and so they set out to build it. Last year transmission capacity doubled between Dallas and Houston. The major players in the transmission business have re-branded themselves and are proud of taking on the role of providing highly reliable service.

Comment: A clarification: National Grid didn't run the pool and doesn't run the BSC in the UK. The pool was parked with the company as a measure of administrative convenience; there was no other corporate entity to put it under. But it was under the governance of the market participants. The big change to NETA is that the government's arrangements have changed, i.e., who sets the rules and exactly how the market works. In the UK model, generation dispatch is done against specifications defined by market participants and the regulator. An independent audit is done every three months. Generation dispatch has always been under the governance of the market organization and should be done that way.

Question: Was the uplift in the pool determined by a decision made by National Grid?

Response: Yes, and the incentives were aligned such that National Grid made money if it got expensive generation off the system. That's what benefited the customer. The company invested five hundred million dollars per year in high tech equipment, phase shifters, new gap conductors, hot wiring, low maintenance asset management policies and so forth. It worked overnight on critical lines and on weekends when it didn't cost money, to drive down congestion.

Comment: We're about to talk about economies of scope in Australia. The way you put your constraint equations, system security and planning together are all variables that can be traded off and co-optimized. National Grid is a very powerful case for what I understand to be economies of scope in the transco. We need to keep alive the discussion of dynamic efficiency versus economies of scope.

Question: A barrier to the formation of transcos is that transmission owners have little incentive to invest. What proposals are there in the US to get owners to actually sell their assets to a transco?

Response: In answer, first divide the world into two. In jurisdictions that have not unbundled for retail choice, if the transmission owner divests, bundled retail service can be provided but the state is losing significant jurisdiction. In other jurisdictions, if transmission owners see an economic benefit to moving assets to an entity, even if they are not active owners of the assets for FERC independence reasons, they can either capture that up front in a premium sale price of the assets, or by retaining passive shares and taking dollars out down the road. They'll have the incentive to create that company.

Question: Does grid ownership have to be coterminous with the markets?

Response: It doesn't have to own all the assets although it's better if it does. You want to put in place an entity that on Day One is an ISO. It has the ability to buy and build transmission. It isn't necessary that the entity own all the transmission assets in the region.

Comment: One barrier to divesting by transmission owners is the current tax treatment. I disagree that the separation of ownership and operation of productive assets is unprecedented and inherently inferior. Where the cost of capital is high, there are companies that will lease equipment. If you have a number of fibers in a cable, for example, you can lease them out.

Response: No doubt there may be circumstances in which creative financing, lease arrangements and the like are a better way so that, technically, ownership and operation are separated. I'm saying that this is the only industry where we're suggesting that they have to be separated.

Question: Your transco model requires the participation of all the assets and owners in the area where the market is going to exist. That's hard to do on a large scale, yet we've come to agree that large regional markets of the proper design are Goal One. I see a clash between this transco concept and the ability to get everyone, including public power, to divest their assets. What happens when one owner says no?

Response: The transco doesn't have to own all the assets. If an owner wants to continue to own, it can lease its assets, or transfer operating control like it does to an ISO. Grid South and West Connect were set up that way. On the other hand, over time, it will be economically compelling to put the assets in the transco if it can operate them better and create value both

for the marketplace and for shareholders. That's why we're restructuring.

Question: What do you mean by transmission operation? Under that definition, who wants operation separated from ownership?

Response: Transmission and operating functions are transferred to an RTO. They include: tariff, OASIS, calculation of ATC, authority to review and approve maintenance outages, line rating approvals and other things that affect the use of the transmission assets. Under FERC Order 2000, those transfer to the RTO. If the assets stay with the owner and those functions go to the RTO, that's what I mean by separating ownership and operations. There are things that RTOs do that are not really transmission. The most important things are system dispatch and managing the market.

Comment: We have a disagreement about the definition of transmission operation because everybody agrees that it includes facilities maintenance, not necessarily things having to do with system dispatch.

Response: O&M can stay under the current regime. What stays with the owner has to be a business in which you create value, attract equity capital and attract good managers. I think that the separation we're creating is never going to allow transmission to emerge from its current orphan status.

Question: The California ISO is a non-profit entity. Some parties think the revenue requirement is too high, but the ISO's witnesses have said that there isn't anything that FERC can do about it because it doesn't have any shareholders, equity and profits. Do you really believe there isn't any incentive difference between a for-profit and a not-for-profit?

Response: I don't think the distinction helps very much with the slicing and dicing debate.

Question: Will FERC have greater control over the incentives for a for-profit transco to control its costs or will it be the same for both?

Response: Jurisdiction to set rates is the same in either case. The inherent problem in a not-for-profit ISO is that there isn't any other place for the dollars to go except a tariff.

Question: Many of my colleagues are more concerned about the potential in the operation of the system for discrimination in favor of transmission than in the planning. Given the data intensity and the real-time instantaneous decision-making, how can you avoid the concern that the transco would not discriminate by the way it operates the system?

Response: First, the transco has to be independent of merchant interest. A transco recovers its operating costs and makes its profit on a combination of ROI and FERC-approved performance rates that presumably would not give the transco incentives to do bad things. I'm not sure that there is any incentive or anything a transmission operator can do that's bad for the market and good for itself.

Comment: From time to time, could an operator choose which generators to utilize to address congestion, and opening and closing lines?

Response: Assume the answer is yes. What's the incentive for the transco to run a more expensive generator, or to open a line that ought to be closed and make the system more expensive or less reliable?

Comment: It depends on the tools and incentives you have to maximize profits.

Response: When and if the transco comes in for incentive rates, it will be subject to FERC scrutiny and scrutiny by consumers. I would rather have profit incentives than not-for-profit ownership.

Comment: A good example is outage decisions and approval. The PJM and New York ISOs have a role in approving them. There can be a conflict between an owner who may want to take an outage when it is convenient in terms of getting the work done, but it may be inopportune from a market point of view.

Comment: If the incentive pricing is to reduce congestion, then the owner doesn't have an incentive to take the line out at the wrong time. Any for-profit entity that's given the wrong incentives in the regulatory process will do the wrong things.

Comment: The goal is to minimize total cost of the system, not necessarily to minimize congestion.

Comment: Assuming that regulators will set sensible incentives to do things that are good for customers, getting the most expensive generators desynchronized from the system is the right thing to do.

Question: What are the assorted liabilities in the new regime? In the old regime, lawyers wrote tariff provisions that disclaimed any responsibility for anything. Now we have new actors, all of who are going to be dependent on how the system operates. How do you evaluate the ability to meet those liabilities by an asset-owning entity like a transco, versus a non-asset ISO?

Response: The lawyers will write those in the ISO/LLC agreements instead of in tariffs. What sort of liability should they be assuming? It's not necessarily the role of the ISO to ensure certain outcomes.

Comment: The ISO cannot be liable for what it does. It has no assets. Any mistakes it makes get passed back to consumers through the participants in the marketplace. A transco doesn't necessarily fix that. But you have a for-profit entity that in normal circumstances would be liable for its negligence. The incentives we count on in our economic system aren't there for not-for-profit entities that don't have assets.

Comment: If the goal is to provide insurance against certain unfortunate outcomes, you could do that in an ISO context, as well as a shareholder or a for-profit entity. You may be able to manage it equally if not better in an ISO context through an insurance means.

Comment: Assume negligence on the part of a transco or ISO. The transco has real assets that are at risk; it can't simply socialize the costs. With an ISO, if the liability is real, the costs are inherently socialized across the system. This is a fundamental issue in terms of which is preferable from a public policy perspective.

Question: This is a transition and robustness question. Agree that it's good to allow vertically integrated utilities to divest their transmission assets to form gridcos, independent transmission companies. Encourage that through incentives through FERC. Require some regulatory mandate to force divestiture, and then require it for municipals, public power authorities and so on. Integrate them into the same independent transco. Do you have to go all of the way for your idea to work effectively, or do you want to go part way?

Response: The current ISO model in the northeast is where we are today.

Response: Encouragement will do the job, but there is huge value to getting transmission unbundled from generation

demand. I don't believe you can have independence without getting those assets out.

Response: Encourage as strongly as you can. If it isn't going to happen, then you need to structure the function. That's one reason why I favor ISO/gridco.

Question: There is a lot of agreement that transmission asset managers need to manage their assets well, upgrade component ratings, and make the wires available when the market needs them. If we're in agreement and we are gridco proponent asset owners, we've got the beginning of a dialogue. Given that you want to maximize profits around the asset, why would you want to do the public-spirited functions that can't be done at a high margin? When you go to LMP, market participants will be driving most of your dispatch solutions.

Response: The first sentence of Part Two of the Federal Power Act is that the wholesale sale and transmission of electricity is affected with the public interest. I disagree with those who say there are particular functions that are public-spirited and others that are not, and therefore some should be performed by not-for-profit entities. We have to decide whether we're going to trust market and private enterprise. Having more functionality inside one entity makes a lot of sense, which is why I prefer the transco model.

Comment: I don't see how you avoid the merchant conflict. I don't think it's possible when you put inherent market functions in a transco. You want to lower congestion, build transmission, and even perform re-dispatch. Of course, generation, location, new generation, transmission location, new transmission all trade off directly as economic substitutes. There are thousands of impacts. If you look at this as a performance-based regulation scheme,

you always have a lot of distortions and inevitably, huge, unintended consequences. To have a performance scheme that works, when you have these inherent conflicts also potentially violates FERC's desire to have nondiscriminatory open access and comparability.

Response: It's important that there are sensible market prices and data that allows generators and load service to understand where prices are likely to go, and to allow the market to solve congestion first through the two mechanisms in generation and demand. Transmission, therefore, should only be built as a last resort. I take exception to LMP being the principal tool for driving transmission investment because of the existing asset problems that are well understood.

Comment: RTOs should not do integrated resource planning. We took generation out of the planning process and we're trying to get retail service out of the planning process and into markets. The RTO is supposed to do transmission planning.

Response: But they're still integrated. If you've got a transco doing planning and that is in a position to make its own investment decisions, it can build ahead of generation and make sure that generation never solves the congestion problem. It's has a fixed revenue that's set for 30 years in the future. It knows that how much it spends is going to affect how much its revenue requirement is set for the next period.

Comment: Theoretically, the transco has an incentive to build and earn a return on transmission. The problem is that we can't get any transmission built.

Comment: Transmission is typically sub 5 percent of the cost base, and the wholesale market is typically 40-60 percent. If you can spend a bit in the 5 percent to dramatically improve the way that 40

percent of the market clears and competes, that's good.

Question: Assume a hypothetical world where most of the generation is government owned and where you want either a government-owned transco, or a government-owned and operated ISO/gridco model, and to attract and increase private investment. What are the advantages of a government-owned transco versus a government-owned ISO/gridco?

Response: First, assume that if you split the two government entities, they would still talk to the energy minister to ask what they had to do. I lean toward separation in the sense that then you would be trying to get private investment in generation, for example. You want generators to go to the ISO to make sure they're getting a good tradeoff between the generation and the transmission and the operations and investment decisions.

Question: Our two objectives are to create large, efficient markets and to bring down the costs of congestion and system operations. Consider a third objective by assuming that there is an RTO planning process that invites ideas and proposals. Is the transco or the ITC more likely to make proposals to invest efficiently?

Response: I don't know when and how you make proposals and how you compare them because the reality of how transmission gets built is that you don't know what your proposal is until you are well down the road. The theoretical economic issue of comparing proposals sounds better than it is in the real world. I don't understand how generation is in this. My understanding is that they're not supposed to be part of any planning process.

Comment: I'm agnostic about whether you should form ITCs. One issue is the potential to focus on a solution that isn't

necessarily least-cost. In New York, a public power authority built a very large transmission line and touted it as an example of having an ITC in the state because it built the line when no one else would. My company thought that the reduction in congestion would not pay for the line. A compelling argument is that a combined ISO/gridco would not have the same interest in creating efficient markets that an independent ISO would.

Question: We make money by benefiting customers by making more efficient use of assets, such as plants running more so we lower the per-unit cost of production. We can eliminate congestion with markets and placement of plants, or by building more transmission. We haven't talked about making use of idle capacity. In gas it's easy to get the right incentives. They have a volumetric rate. They can run a lot more throughout through. They don't have to come back for a rate case. They see the value. In electricity, in most states, the money goes back into next year's rate case, or it is part of a true-up, the incentives are lost and consumers lose the benefit of using that idle capacity. How do we get incentives?

Response: Create an entity that has a reason to look for ways to create value in the marketplace and give it pricing that allows it to take some of that value back to its shareholders.

Comment: Regulatory deals that don't claw back additional revenues would be helpful.

Comment: For transmission, the standard rate design is that you pay the incremental cost associated with using it and the fixed costs that aren't recovered through those prices, FTRs and so forth, are recovered from loads on a more or less fixed basis. It's hard to do perfectly, but rate design can help.

Comment: If transmission costs are only 4-5 percent of the total bill, is it appropriate to give it a level of equality on the issue of squeezing efficiencies out of investment and operation of the system, rather than focusing on the issues of control as they leverage the market for generation, for the substitutes for generation and so forth? Suppose you could reduce transmission costs to zero. You save 5 percent of the bill. If you haven't resolved the control issues, then you create market distortions in a big part of the rest of the bill, not necessarily the distribution and revenue cycle services, but the generation piece. I don't think there's a lot of disagreement that the generation markets aren't terribly efficient. It's probably going to be awhile before they actually get there.

Response: It's not the percentage of transmission investment versus total cost. Having inadequate or badly run transmission creates congestion and increases energy and generation costs. Those are the dollars we're going after. We have a system that was built for a monopoly situation where, in essence, we traded off generation and transmission, deliberately creating must run, if you will, on non-market conditions. We're looking at making investments in transmission that we know are small relative to the total, in order to create really large savings in the cost of energy.

Question: Whether you use command and control and a regulated rate of return or ask a merchant to come in, how big a deal is it how you get there?

Comment: I think most transmission will be built in a command and control way. But I want a company looking at what needs to get built and figuring out the most creative ways, so that you don't have to say, "Get out there and build that." In a regulated business, entities that have an incentive and then get a fair return on their investment will attract a certain kind of

investor and that's what we want. A not-for-profit entity doesn't have those same incentives.

Comment: Five percent if it's spent well, will free up the 40-60 percent of the wholesale market. That's the benefit. Regulators really should think hard about which bits of the transmission costs should be incentivized. Investment, operational expenditure, congestion and throughput can be incentivized. Where's the balance in these? Investment, hammering down congestion and pushing up throughput are very important.

Comment: The real question is that the two models won't be able to find ways to reduce congestion quite as well as an integrated entity might. But you have to trade that off against additional benefits from having both the ISO and the gridco looking for things to do. A gridco would have strong incentives to find opportunities to invest money.