Harvard Electricity Policy Group
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RAPPORTEUR'S SUMMARY*

Session 1. Missing Markets and Unintended Consequences

Get the prices right and the market will do its magic. This simple mantra contains the important truth that without appropriate prices it would be a surprise if the market worked well. But good pricing is not enough. Unbundling reveals that there are many products and services embedded in delivered electricity. There are so many possible product definitions that it would be unlikely to separate them all, design the many markets with all their interactions, and get all the prices right.

This raises several questions that should reflect the developing experience. What are the products that should be defined, priced and paid for as unbundled transactions? For example, would hourly energy settlements be adequate, or five minutes? Different market models would price losses, reliability, reserves, voltage support, reactive power, admittance, transmission, and so on. Not all these have explicit markets today. Where should we draw the line? And how do we deal with the markets that are missing?

There is an argument that some markets may destroy others. For example, there are markets that prevent efficient short-term balancing markets to force greater reliance on long-term arrangements. Should we impose constraints on some markets to force parties into others, such as out of spot market and into long-term bilateral deals? What is the balance between socialized command-and-control (e.g., black start capability) and price-driven market transactions (e.g., real-time balancing)? How do market operators compensate for missing markets?

Speaker 1.

I'm going to continue an ongoing discussion that focuses on reliability and scarcity pricing, operating reserves, and demand curves.

Currently, demand for energy involves a group of customers who are characterized by inflexible demand. If they were able to respond because they had appropriate metering and controls then they would have varying values for their demand but they can't respond. If they're going to be curtailed, they have to be curtailed on average for equity. This means that there is an effective horizontal demand curve for the system operator who sees the average value of lost load, not the marginal value. This implicit demand for inflexible load defines the opportunity costs as the average value of lost load [VOLL]. If you add this group to others that can bid, then you get a total demand curve characterized by a normal price curve, a plateau which represents inflexible demand, and then a further diagonal price curve. There are various implications for this situation; one of them is the role of the reserve demand curve.

Generally including an operating reserve demand curve seems like a good idea, especially for the difficulties with operating reliability and incentives when the system gets short. In the context of resource adequacy, it's useful for improving scarcity pricing to provide incentives for the long run.

We need an operating reserve requirement, and that's already in the system. However, the notion that demand is vertical doesn't make sense. It's solely an administrative determination given the technology. Given that an administrative rule is necessary for the determination of the reserve requirement, why not reflect the opportunity costs in the demands as best as possible? This would provide a tool for better scarcity pricing and a proxy for demand bidding for energy. If we had demand bidding for energy that would be good also. The two are not mutually exclusive; you could do both.

The question is how to characterize a curve for operating reserve demand. If the operator is down to a low enough operating reserve where the concern is for largest contingency and catastrophic failure then the price should be the value of loss load. This is where the reserve line indicates that the operator will start curtailing people. If the operator is above that bare minimum, say around 3%, then increased amounts of operating reserve would be useful depending on a price. Unlike the 3% reserve which functions at Value of Lost Load, the reserve between the minimum system failure (3%) and a nominal reserve target (say 7%) should involve a normal price sensitive demand curve. This function can be combined with energy and operating reserve demand in a simultaneous determination of prices. It provides a mechanism for scarcity pricing even though there are offer caps and there isn't enough demand side bidding in energy.

That's the background. And what I'm trying to do today is to connect reliability and market design more fully. What is this operating reserve demand curve, and how would it be derived? The principle is the context of dispatch based pricing. The philosophy behind this is that the operator knows what they're doing but after they've done it, they determine prices in a way consistent with what they did. So the operator analyzes the dispatch and the implications for prices. It's done in the LMP context; a well-established principle. In a normal situation, where demand is low and capacity available, the reserves would hit targets at a low price, say $30. In a scarcity situation, the price could be much higher, say $7,000 in a market with a $10,000 average VOLL. While this does introduce market pricing to reserves, it is not the answer to all our problems for operating reserves.

Simplified models show this can work and make locational reserve requirements operate with an operating reserve demand curve. The New York ISO already includes locational spinning reserve demand curves and ISO New England is in the process of trying to implement it using violation penalties that function like a demand curve. They're talking about doing a similar thing in Texas.

What I want you to accept for the present discussion is that the simplifications I've done along the way are reasonable. With these simplifications, this model looks very much like economic dispatch right now. It just has an added term in the objective function which is the value of the expected unserved energy. This recognizes that in some circumstances the operator may not be able to meet all the load and will have to curtail people. There is some low probability and that value has been included.

There's two difficulties in the model so far. First, it does not include security constraints such as deterministic security constraint or n-1 contingency. How do we handle security constraints? Second, it also doesn't address the problem of unserved energy if people are curtailed. How is the value of unserved energy derived? I want to outline the answers for each of those components.

The critical story here with respect to unserved energy is: we have an expected peak load in the next half hour but it might be higher or lower because it's uncertain. The operator must make commitment decisions beforehand. In a single period they decide before but experience it afterwards.

Second, some of the plants or transmission lines may trip out and the capacity won't actually be there. The response to that is a random process. The response is loss of load probability calculations, which are familiar to the electrical engineers. This is nothing new. The usual constraint that's discussed is that the loss of load probability should be less than something. So they set a target at "something" and they want it to be below that. That's the constraint. Unfortunately, that constraint means that outages which are beyond it are infinitely valuable and outages below it don't cost anything (or cost very little). The demand curve approach attempts to improve on that.

The model simply calculates loss of load probability in the usual way and also the expected unserved energy. The average value of loss load allows one to calculate the value of unserved energy, and various other things follow from that which I'll describe.

This model assumes a relatively short period of time. This means low probabilities of bad things happening, including a strong possibility that nothing happens. Outages and loss in increased demand are only a small possibility. The intercept probability of zero loss is less than 1, the load change will not be greater than that. Again, I'm going to make a series of assumptions and we'll assume they're all reasonable, OK? [laughter]

This all results in an operating reserve demand curve defined by a particular probability distribution. There are simplified assumptions to make the calculations easy. It's a normal distribution with particular assumptions about mean and variance. I've run examples which create a peak load in New York State and show how much they're going to lose over the next half hour and the variance in those expectations. While the exact numbers are not perfect, they're of the right order of magnitude.

This model has an interesting property. If one is looking at different levels of load and commitment, a general probability of outage, the probability of excess load distribution for higher and lower values of the expected load remains constant if it has the same relative size. If you double the expected load, you double the width of the distribution. If that's constant then it turns out the operating reserve demand curve expressed in terms of percentage of expected load is also constant. There's only one curve. The curve only has to be calculated once if the assumptions are approximately right. This is a great advantage because it means you don't have to redo it every time.

There's a problem though. So far the model assumes away the network and the security constraints. However, I want to put them back in. The first security constraint is minimum reserves that are larger than the largest contingency generation loss so the system doesn't go out. I've assumed 500 megawatts, which is order of magnitude in New York. This security reserve interacts with the operating reserve demand curve like a big step. I've set the price for that at $10,000. If we don't have enough operating reserves to meet the contingency requirement the curtailment is $10,000. That was the easy part.

Next, what happens to the demand curve to the right of the 500 MW minimum contingency? If demand is going above 500 megawatts, there's some probability that the load will be higher than the expected load or there'll be outages. And if there are, we'll fall below the minimum contingency operating reserves during the period. The model allows for curtailing load during the period in order to meet the contingency, thus the operator would be willing to pay $10,000 times the probability that something like that would happen. Remember, I discussed earlier that the probability is less than 1, so that's why a $6,000 starting point would be implemented. It reflects the value of the expected unserved energy and the security minimum together. This is what the operating reserve demand curve should really look like. In New York, the highest price that they get if all their constraints are operating is about $1400. That's around the 1,000-megawatt level.

You calculate the value of expected, unserved energy applied by the curve above the minimum that's being ignored in current operator models and it's significant. Remember I discussed before that at the minimum reserve level everything to the left is infinite cost and everything to the right is free. In this approach I took reasonable calculations as to the average cost of meeting the load. The value of unserved energy is 184% of the average cost of generation. That's the cost that's being ignored. If you take only the minimum level, it drops to about 55%. That is still a big number. Currently that available generation is valued at zero when it should be at least 55% of average generation cost. It's non-trivial and important.

Finally, the time issue and the network problem are hard. Essentially you have to do everything that I have modeled at every single node. You develop an operating reserve demand curve at every node in the same way. It's not necessarily so difficult.

However, one also has to address the fact an operator with an operating reserve demand curve in the East might use operating reserves in the West to meet requirements in the East? A zonal solution may work here.

There are two ways to do that. In New York they use a nested, zonal model. This means that the operating reserve demand curve is actually a premium that applied to the several constraints. Since it's nested, reserves in New York City affect more than one constraint. When all constraints are active, the prices can add up. Prices for reserves in New York City are above the price determined by the demand curve. The demand curve only implicitly sets prices, it's not explicit.

In PJM there's an interface limit. One can only move so much operating reserve from other places for this calculation. This a bit more appealing but there's not a huge difference between the two approaches.

Speaker 2.

I'll discuss missing market participants and products. It comes up frequently in discussions where people are upset with the prices that they're paying. FERC is still in the business of promoting competition and they're trying to refine what that means. Stakeholders often make assumptions about how the market design operates. These assume perfect information, and are over-simplified. In these situations, you lose the perfect hedge. The reality is the perfect hedge wasn't there anyhow because the assumptions are wrong. Good market design is an art and a science; there are simplifications and over-simplifications.

The overall goals are to encourage efficient investment, maintain reliability, and encourage efficient dispatch with active market participants. Market participants include the demand side and transmission. Transmission is generally assumed to be passive. A goal that's sometimes missing is innovation. When one debates cost of service versus markets in terms of efficiency you may get a slight edge for competition, depending on your political philosophy. However, the incentives for innovation are much more stark..

In cost of service, the incentives for both efficiency and innovation are weak. 20 years ago, the FERC set out to remove as much cost of service regulation as it could. It started in gas, reasonably successfully, and then moved to electricity.

I use the term "market-based regulation," not competition, or laissez-faire, or free markets. The law says that FERC has to make sure rates are just and reasonable. We're never going to be able to give up mitigation. In some sense, cost of service is probably the worst, meanest type of mitigation of market power.

The assumptions in the previous speaker's presentation involved a DC model, but the system is an AC model; a lot of additional complications. The thermal constraints in the DC model are only estimations from one or maybe several AC load flow simulations. Further, it's usually a non-convex world, with dispatch models that have startup and no-load functions; linear pricing doesn't do you much good. Simple models don't perform the normal functions of market clearing when we assume convexity.

Rather than talk about reactive power, I'm going to talk about wool and mutton. Suppose a government, maybe in New Zealand, makes a rule that if you raise sheep you can sell the wool but have to give away the mutton. It's a pretty good rule, right? Eventually, the people breed sheep that are pretty skinny with little mutton and a lot of wool. Soon the sheep are so weak they can't stand up. Soon, you go back on the market and subsidize mutton production or maybe buy steaks. This is exactly the story for re-owned reactive power in the generation market. The merchant generators have to give away their reactive power at no extra cost. If that trend continues then generators will be scaled-down with as little reactive power capability as possible.

Transmission markets have to be considered in the context of a national policy that says we don't have enough transmission. However the transmission literature uses every metric in the world except monetary measures. They measure outages per this and that, a whole litany of indexes that they calculate. However, the signals for transmission investment are weak, even destabilizing. The Transcos are the new generation of transmission and come in two flavors: cost of service and merchant. The cost of service Transcos don't do or own anything but transmission and are all embedded in ISOs. The merchant Transcos have no rate base to recover costs. There's one in operation and several more in active process.

You can have entry competition for transmission, it's not such a radical idea. To get the most efficient investment, even if it's planned, you can have auctions to build the transmission, and competitive solicitation for financing. However, those in vertically integrated transmission don't find this very interesting; they disapprove even. The same arguments were used against independent and merchant generation some time ago.

If we have reactive power and transmission as active players in the market it can increase the efficiency. This proposal is not something that could be implemented soon but assume we use zonal reserve markets, and everyone is paid nodal prices, including transmission, and both real and reactive power. Some nice properties emerge: the pricing system is revenue neutral, the operator need to invest money in the system. Zonal prices are revenue adequate. You may actually collect more than you need. You can make the system non-confiscatory to address that. However, you can't make this work with linear prices.

Let's consider a transmission line with no capacity. If the line's circuit breaker is closed, the difference in its nodal prices means it could be in a situation where it will owe money to the system operator. If so the line operator would call up the system operator and say, please open my circuit breaker. The circuit breaker is nothing more than a unit commitment variable.

Almost all generators have a unit commitment function, and the operator has to commit it to the market. In almost all the markets if the operator commits a unit to market, it guarantees its bid cost. Why can't we do the same thing for transmission and guarantee its bid cost? Well, what happens? If you give them the same rule for unit commitment of generators, they'll commit the transmission element to the market. The overall market surplus will be higher. The line is now getting its bid costs so to speak. Further, a merchant generator could actually have a positive price on its unit commitment because it had no other way of recovering its capital costs.

This approach creates a whole bunch of interesting issues. I'm still not sure I would advocate the approach wholeheartedly but it's something to think about. The fundamental idea is to make transmission a completely passive entity in these markets. It's somewhat offensive because many folks have been very aggressive about allowing merchants to play in this market. I'm not sure we want to deny that capability to transmission owner operators. Further, in its full blown operations this would be a complicated model to operate. However, it creates interesting options. For example, one could allow the transmission owner to run assets slightly beyond their nominal capacity if it could fetch a certain price. That could be easily implemented in these dispatch models.

If you're offended by merchant transmission or active transmission participants this isn't for you. A reminder that efficiency is a goal but innovation is a bigger goal. Without these market incentives we'd get virtually no innovation whatsoever.

Speaker 1: A quick clarification. If a transmission owner is going to run equipment, are you talking about sacrificing loss of line-life to bet more money?

Speaker 2: Yes. A merchant transmission owner could have the right incentives to run their line at a higher capacity if they are paid enough money. If it's not done for long it doesn't even do very much damage. If you get into the $10,000 loss of load probabilities it gets complicated because it reduces the reliability margins.

Speaker 1: Yes, it gets complex.

Speaker 2: If you've got $10,000 prices and there are not other reliability issues, a transmission owner could be willing to run their wires hot to make some good money.

Speaker 3.

My discussion is more philosophical and involves a broader overview. I'll talk a bit about missing markets, their implications, some examples in history, and try to draw some conclusions.

Markets are wonderful things, especially when history indicates they are. When a new opening for markets comes along, we want to maximize the role of markets and prices in solving this problem. However, there are logical and practical limits. Even in theory there are problems*:* the non-convexities that Dick mentioned, monopoly issues, market power issues, and important social values other than efficiency which come into play. There's an awful lot that's not driven by markets.

The basic function of a firm is to internalize transactions so that you don't need markets. A firm can allocate resources by central administrative decree rather than trying to price everything. Internalized transactions reduce transaction costs, internalize scale economies up to a point, and so on. In practice, we make decisions, and many outcomes occur in which decisions are internalized within an organization. The big question is where to draw the line between these things.

Integrated electricity systems need a large facility, centralized dispatch, centralized coordination of various kinds. They use mathematical planning and dispatch processes. When competition in electricity began to look politically and commercially attractive, market wonks looked for a market solution in the central dispatch process. Various multipliers came out as prices, and the market wonks said let's create as many markets as we can.

In the UK 15 years ago, Margaret Thatcher made a political decision to have markets and nobody knew how to do it. Eventually they used a process basis derived from the central dispatch process and the market developed from there. I'm talking about the multipliers that come out of any constrained optimization process that can be logically transformed into prices.

Dealing efficiently with these constraints involves two things. One is maximizing the value of real time operations within the constraints. Second is to invest to ease the constraints to reduce operating costs. The question is whether the markets the best way to do this.

Constraints can be managed in two dramatically different ways. One, we just have to price constraints well; competition in the market will determine prices, or they'll be set by an administrative process. If the prices are right, the responses will be also. The second way is to go back to the firm. Firms can manage these constraints internally. Regulators can say to monopoly type firms, you deal with it and we'll give you incentives to do it well. In practice we always do some combination of these things. It's not practical to price everything precisely right, so some monopolies are chosen to internalize it some way.

Traditionally integrated monopolies did it all. All prices did in the traditional monopoly utilities was collect money to cover the costs. As markets developed the monopoly shrank. PURPA started as a single buyer model and tried to let the market choose generation assets and to some extent the amount, but mostly just the type of assets. In the SMD, there's still a monopoly there, but now the monopoly primarily operates the market as kind of an agent. Matches buyers and sellers, operates a process that determines prices, provide some ancillary services. This can be done in a market determined way, but a monopoly still does it.

The best example that illustrates the tensions between these models is the ISO Gridco model and the Transco model. The Gridco model has two separate organizations, the grid owner and operator operates under ISO instructions. The ISO is responsible for the operational decisions, the markets, telling the Gridco what to do, perhaps making investment decisions. The Gridco operates, maintains and builds the assets, and is paid to do that. The ISO takes the markets as far as possible, this model maximizes the role of markets. It means that you've got to develop sophisticated complex markets. This divides activities between two entities which creates problems. It also has some advantages, creates some checks and balances. They can keep an eye on each other, but it does diffuse responsibility.

The Transco model operates the whole transmission system, including dispatching transmission and generation and necessary services. The best example is National Grid Company [NGC] in the UK which owns, maintains, operates, plans and invests in the grid. They internalize everything within one entity, manage operations primarily by scheduling bilateral transactions and penalize deviations from schedules and imbalances. They pay for ancillary services and congestion as a monopoly. It internalizes costs, and has performance incentives to keep costs down. It tells the market participant: you don't worry about these problems, they're my problems, just go out there and act as though transmission is always set, we'll take care of the rest. The UK operates like this, and the EU hopes to make this kind of model work.

This requires less sophisticated and complex markets. The market trading is done in decentralized markets and difficult technical issues are internalized by the Transco. An advantage is that it combines system operations and grid operations in one entity. In the Gridco ISO model, keeping the incentives right is hard between the two entities; this model internalizes it which is good. The main problem is that it is a big monopoly. You don't know what they're doing; it's opaque, it's powerful, it usually makes a lot of money. NGC is a very profitable company. They write their own incentive rules which nobody can understand. It always manages to do well under it. The two models demonstrate the distinction in electricity markets. You put a price on it, create a market, or you just say to somebody, send us a bill, and don't hurt us too badly.

A variation on early monopoly models is an integrated monopoly, going back to the first pool based markets in 1982. It's been adopted in a lot of Latin America. It's based primarily on bilateral contracts where generators operate a generator pool, and dispatch their plants internally. They settle things among themselves to meet contract demands. It's a cartel model because nobody else can play in the pool, but it's done pretty well.

In 1991, the UK introduced a gross pool in which everything's bought and sold there. All contract transactions are in the form of bilateral contracts for differences. In that market National Grid was acting more like an ISO. It still internalized ancillary services and congestion management. There was no pricing of congestion through an LMP system, there still isn't. Everything was internalized within NGC. This was an advance over the Chilean model because it was a more open market and had better pricing.

In the mid-1990's, LMP [locational marginal pricing] and FTR [financial transmission rights] systems were introduced to push pricing down, and to price congestion, ancillary services, and reserves in the market. This has been implemented a bunch of places, and it seemed like it might be the wave of the future.

However, California had its disaster in 1999, which was a bit of an aberration. In the early 2000's the UK actually scrapped the pool and replaced it with new electricity trading arrangements. This now includes Scotland, but not yet Northern Ireland. They replaced it with a buyer lateral contracting mechanism and a balancing market. They call it a balancing mechanism because they don't want anyone to conceive of it as a market. It includes penalty functions for bilateral imbalances. NGC manages ancillary services, the congestion and everything else. It internalizes it all and players in the market act as though there were no constraints. This is causing some problems but it's working more or less.

Today Europe is trying to set up open access arrangements that allow competition. They're making some progress; the state monopolies are buying each other up and creating bigger monopolies. They call that competition. They still use physical transmission rights at borders which is a problem. The movement towards markets is not exactly uninterrupted or inevitable.

I still believe that well designed markets can do more. Not everybody agrees with this, and it's not just because they're perverse or stupid. There are different views on this matter. There really are important natural monopoly elements that we can't price very well, even in theory. Practical compromises are hard to find. It's not easy to design good markets, and getting it wrong can be disastrous. Others are more willing to tolerate NGC type opaque monopolies.

I'm not nearly as evangelical on these issues as I was. It's hard to keep these markets going. I'm on record saying it would be a disaster in the UK. However, they're happy. Nobody's complaining much. They have far fewer committees and processes than we do. They just how much to pay NGC to take care of it all; everybody else buys and sells and ignores it, and it works.

Speaker 4.

I'm going to talk about extending nodal pricing and megawatt mile methods to the distribution system. I'm talking about distribution systems and not wholesale markets, and I wasn't sure about a connection to missing markets. However, there is a connection between distribution, transmission, and wholesale markets here, something I didn't realize.

Why consider nodal pricing for distribution? Initially the context of South America was the focus. This is a way to provide better incentives for siting distributed generation and other distributed resources. This includes demand side responsiveness in markets, or even in the cost of service model. It rewards sources for reducing line losses and line utilization. This is no different than similar incentives in transmission. You also want to penalize sources that increase losses and/or system utilization.

The model provides a revenue source for distributed generation [DG] without relying on ad hoc subsidies. Distributed generation is generally not recognized, or net metering pays the same average price as loads pay. There's no recognition of the additional capacity that they create.

As a general rule distribution systems are designed so they don't become congested. The major concern is reducing line losses. Of course, congestion could come into play where there are mesh networks. The system example I am considering (with nodal pricing) is only approximately sixty kilometers; a relatively short distance. Keep that in mind when we discuss prices, and losses.

The prices in a South American example would include the fact that natural gas was quite cheap. Later on, the Argentines curtailed gas deliveries to Chile and Uruguay and Brazil. Generally, a distributed generation source will receive a nodal price at the interface with transmission in each hour. This ignores marginal losses on the distribution system. Another option is nodal pricing on distribution when marginal losses are recognized. One could assume a 1 megawatt micro turbine generator that can run at all hours. It can still be economic even given the price of gas if the prices are high enough at the last node. It could be operated at a lagging power factor of .95, so it produces reactive power.

Prices at a given node at different time periods (off peak, shoulder day, peak and shoulder evening) are significantly affected if one implements distributed generation and uses a nodal system in distribution systems. Marginal losses on distribution systems where you have small conductors can increase rapidly. Significant savings are possible if we price distribution and get distributed resources or demand response in the right place. With distributed generation, the price impact is mitigated somewhat, but still notable. In distribution systems with small peak loads (e.g. 5 megawatts) large losses can accumulate rapidly so the implications of this process are useful.

The DG resource gets increased revenue of about 12% greater. Compared to an average cost rate in cost-of-service, the revenue difference would probably be greater.

The question is how this might affect wholesale markets. If we're considering nodal prices at the distribution level with time and locational differentiation, it brings demand back to the wholesale market as a distributed resource. Demand's going to receive the same types of price signals as players on the high voltage system. They should be able to react accordingly. It isn't impossible for small residential consumers to react. In Florida, Gulf Power has managed to create real response with time and use metering. Nodal pricing at that level could be very successful.

Clearly, there will be shifts in cost burden, because the marginal losses have been socialized. People at the end of the line have been supported by those close to the interface. There are potent political issues. Consider the issues in Connecticut with Attorney General Blumenthal. Demand response and DG at lower voltages could also become players in reserve markets and ancillary service markets. They could equalize prices across zones, as discussed in the first presentation about zonal markets for reserves. There might even be a market for reactive power here. I've run models that price out reactive power, assuming it has zero price in the market. Losses for reactive power, if priced at the cost of real power, as New York and PJM now do as an opportunity cost price, could be significant. This is a potential for significant payouts to distributed resources. It's a real incentive to develop them.

To implement this in a wholesale paradigm, we have to consider some issues if we're dispatching distribution along with the transmission system. It is computationally difficult to avoid some of the seams issues. There are enough seams issues between transmission and distribution. Furthermore, there could be all kinds of jurisdictional fights, as if we don't have enough between the states and FERC.

At the distribution level, there may be issues with transmission charges. If they're being assessed on a megawatt hour basis, then demand responsiveness or DG embedded below the high voltage system implies there is less power flowing over the transmission system. This means that per megawatt hour charges for cost recovery have to increase. There may be a need to think about pricing it a different way; perhaps pricing transmission services on a fixed basis, rather than per megawatt hour.

Another approach for consideration is megawatt mile methods. Transmission owners are familiar with this. The location signals in distribution would be allocated toward the fixed cost of the system. This recognizes that nodal prices cannot cover all of the fixed costs. It can be argued that the nodal prices don't provide adequate long term signals. This proposal charges customers based on extent of use. It rewards demand or supply resources at the distribution level for providing counterflow to the system somewhat. This could be controversial in Brazil and Argentina. Counterflow is often charged within these systems instead of being rewarded. Generators and loads feel that that's not fair. It doesn't give them an incentive to locate in the right place.

I'd prefer a variant, an amp mile method. This recognizes that distribution systems are often designed to handle current flows rather than megavolt amperes because voltages may fluctuate more on the distribution system than the transmission system. Otherwise, the methodology is similar to traditional megawatt mile. The charges should be based on the coincidence system peak. This can be broken down into a system peak for each season. The entire circuit capacity could be charged based on this methodology.

It might be more politically acceptable to apply these locational amp mile charges for capacity in the distribution system. I'm not saying it's right or wrong. If one only charges for use capacity, this approach has a nice property. When one fully loads assets, the locational charges are assessed for the full asset. There's a real signal when the asset gets increasing use, until it's fully used.

In current systems, large industrial customers don't pay much more than the residential customers in total over the years. This is despite the fact that they have a huge peak load ,and a much larger load over the year. If the amp mile charge is implemented with both locational and non-locational components, the industrial customer pays for more of the system. This is because they have a huge peak compared to the residential customer. The industrial will pay for more of the system, even if the residential customer is about halfway down the line of the distribution system.

The further you are from the distribution transmission interface, the greater the charges. It works similarly for distributed generation. Except in that case, DG gets paid for providing capacity on the system.

The changes in the charges are due to location and moving from a per megawatt hour basis to a coincident peak basis. Currently I am working on models that decompose these changes from using the amp mile method with nodal pricing to see what's really driving this. Is it primarily the move to coincident peak or is it the locational change.

The overall idea is to recognize that sources can create distribution capacity, with implications for transmission. If we're going to have merchant transmission to build transmission assets, then another substitute for transmission is to create capacity with counterflow. It's a market where demand response or distributed resources create not only distribution capacity, but also transmission capacity.

The most important missing element for wholesale markets is demand response. That says it all. We can't have markets with just the supply side, it's like the sound of one hand clapping. These megawatt mile methods could address one of the mandates of the energy policy act, which is to reduce transmission costs. However, they do it without having to build new transmission or increasing incentives for transmission and the rate base.

Question: My question relates to the RTO/ISO model. One speaker described system operators as monopolists. However, a key distinction is that these entities are not for profit. If we consider efficiency incentives and we are pushing harder to make markets work is a not-for-profit ISO or RTO a sustainable mechanism, or is that a way station?

Speaker 2: This has been a big issue at FERC because ISOs send a memo on cost controls and FERC summarily approves it. It's called formula rates. There's probably a little bit of fat in the ISOs, but there are studies that show 100:1 benefit to cost ratios and 0.1 benefit to cost ratios, so you could take a geometric average I suppose. There are places where you could save money. MISO probably incurred a lot of startup costs.

Alternately, there's still efficiencies in market designs. My current favorite is that PJM switches to mixed integer programming for their day ahead unit commitment. They run the software on a sampling of their previous year's bids which shows they saved $54 million a year. For an entity with a $100 million budget, a couple of $54 million savings pretty much covers things. There's more software savings to be had too. For example, there are entities who still load that can't bid nodally into the market because of simplifications in the market design. Further, maybe the gains from having reactive power markets are only 3 or 4%, but in the U.S. this is billions of dollars. The gains are huge. If we are worried about $100 million investments when there are billion dollar gains, we're selling the process short. You can incent nonprofit organizations. Every one of them has a bonus program.

Speaker 3: It's hard to define what's a way station, and what's progress. For instance, the UK pool was OK as a way to start, but now they've moved to a bilateral market, and there's real progress.

Speaker: This is a more limited question in this case than is often assumed. The alternative, the counterfactual still involves other rules, design, and regulation. All the rules are necessary – we're going to have some kind of apparatus and design and the question is just how good it is. If you get a big enough monopoly to cover all costs, this is the UK story, and you internalize everything. This is not practical for the U.S., because it's too big. There's all these organizations interacting with each other.

Second, between for profit and not for profit. Either way it has all kinds of rules, regulations, and oversight on it. This question has less there than meets the eye. It's hard to set rules for incentives in organizations, especially nonprofits. However it doesn't matter so much because of all these complicated rules. There's no simple fix. Providing good incentives for system operators is very important in any case, even if it is hard. It can be done.

Is this a sustainable model? Well, it's unusual. Neither it, nor an interconnected grid, is what we normally think of in various kinds of markets. There's an inherent design derived from fundamentals, not just because people decided the like not-for-profits. I do think there's a sustainable model if we do it well.

Question: There is a lot to be gained if you can bid transmission into the market. However, this is being done. Most competent utilities do that on an asset management basis. Do you increase a rating for a short period of time, rather than make the investment now? The proposal is to put that into a market environment. My question is whether nondiscrimination comparability problems arise. Does the operator treat these resources as demand resources, saying, I'll give you in advance x number of megawatts for x hours, so that they're not picking and choosing when they get them? Second, standard ratings must be considered first. Consider a manufacturer rating of a 300 MVA transformer. However, I know companies rate it at 405 MVA and others at 300 MVA. That affects the bidding.

Speaker: I agree. However, whenever someone says it's impossible to do with transmission, I remind them that generation in 1980 had analogous arguments. What a utility calls a 400 capacity unit has the same analogy in generation. The capacity of the generation units and transmission elements have to be assessed solely on what they can and can't do. We did get beyond that in generation. Certainly transmission is more complicated, but not impossible.

Comment: This gets into jurisdictional issues, and the responsibility is not clear. Everyone has methods for rating equipment, but you can go to a standard method. The proposal would receive an SMD type negative reaction when stakeholders begin to fight over who gets to decide those standards. My question only asked whether creating some standards is necessary for the proposal to work. It's not difficult from a technical perspective, it's more difficult from a political regulatory perspective.

Speaker: One of my caveats was, don't try this at home. It's something to think about. Determining the capacity and physical characteristics, has to happen in the reliability process, just like the market process. We can't simply finesse the capacity of the transmission system, or its characteristics, if we're going to do reliability properly. All the things needed for reliability exist already, free. There's no extra charge to get to the market, except to put a price on it.

Question: This question relates to the proposal of the first speaker. Caps are always a political issue. There are also regulatory mechanisms to protect demand, as high prices, if it is not capable of doing that itself. If demand is not capable of hedging another price in advance, or using other mechanisms, then we produce caps to protect them. In theory, if demand is capable of hedging itself against high prices, then you don't need caps at all.

Generally the cap is related to the cost of the gas they're buying, relative to the customer. In the results of your model, does your result apply to the lower end of that scale, where there is no cap and they are fully hedged (or when they could hedge themselves fully). Or does it apply to somewhere in between?

Speaker 1: That's a good question. If you have an imperfection (in economist terms) of a price cap, and there's a low price cap, it creates unique incentives and effects. The implications for the operating reserves are unclear. My first order guess is that it doesn't change the qualitative care. You would still want an operating reserve demand curve. It would probably increase the level of the load but not necessarily the load above the margin of the operating reserve. That is what drives the analysis. You'd get the inefficiency that we always know about, which is that the demand is too high, but it's not obvious to me that the demand curve operation is significantly different in either context. Let me think about that, that's a good question.

Moderator: Thank you for demonstrating that both the question and the answer are beyond my understanding [laughter].

Question: In the Northeast, we're intent on having markets at any cost but we're not necessarily clear on where the assumptions lead us. LMP pricing was supposed to create market responses. That hasn't occurred and the response has been that some fixes are not economic.

Similarly, since transmission isn't being built to make markets viable, the transmission incentives being discussed seem to imply we throw money at the problem. Transmission operators seem to believe they don't address their needs. Their needs are to have a single source for transmission approval, and then a clear path for cost recovery. These incentives don't solve those problems.

If we are bent on markets, should we examine these assumptions? If the solutions are not working, the consumer is paying. In our region the problem of congestion was resolved through a settlement agreement with the utility who wanted to merge with another company, not through markets. I look forward to your comments.

Speaker 1: Many of the deficiencies have not been because of markets, depending on how you characterize it, I guess. We haven't been sensitive enough to analyze it well. We've been too willing to compromise on things, because it's politically difficult to do anything else. The details in market design are tremendously important.

Many have wanted to assume away the character of the grid and locational pricing issues. That puts us in even more serious trouble. There are other significant problems, such as those you've identified. People will respond to the incentives that you give them.

Speaker 2: To me, the process always involves markets, that includes cost of service. A company sends a bill, based on assumptions and regulations, and the customer pays, it's a market transaction. We try to solve transmission issues with a planning process, and we haven't. Some assume that there's coherent planning when we have things like the Cross Sound Cable. Right now it sits in both New England ISO and the New York ISO. It can produce reactive power to stabilize the New York side of the grid but the New York ISO has no capability to pay them, because there's no tariff provision to pay them for reactive power. It's an issue waiting to be dealt with.

If there's a congestion problem, we can't blame markets, because there's no entry ability for transmission assets. Transmission can't solve a problem in a market context if there's no good write away process. Most states have laws that say that transmission must benefit the state itself. If a line simply crosses a state then there's no benefit seen. For 20 years, people have been proposing a line across Pennsylvania that will never get built.

Speaker 3: These siting problems and others are a different dimension from the market and the monopoly issues previously discussed. They're going to be there no matter which approach we take. We don't necessarily have to price everything. There may be some solutions that are more practical or easier otherwise. However, the market approach does bring some solutions to the problem.

Speaker 4: Congestion is going to exist in a market or a regulated environment. Moreover, the solution may exist in a regulated environment. Consider the real time pricing that Southern Company has been doing. They aren't in any wholesale market, but in some of their service territories they're using time of use pricing. Their large commercial and industrial customers have real time pricing that includes day ahead forecasts.

It's a false choice, market or no market. We could have these incentives, even LMP, in a vertically integrated environment. The principles are the same. If we argue about what happened in California five years ago, prices went up, and suddenly the crisis was over. Natural gas prices this past winter also went up a lot but there wasn't the same outcry as with electricity.

If we consider recovery of cost for a new transmission line, we need to think more creatively, outside the cost of service realm. There are alternatives; different regulatory mechanisms than rate of return or cost of service. Maybe revenue or cost caps, as they're being used in the UK, can change the risk profile between rate payers and the utility for cost recovery.

Question: Let's discuss the wool mutton analogy used earlier. The wool and mutton are separately demanded by consumers. In the case of reactive power, it doesn't seem like the same situation. The analogy is fuzzy also if applied to the question of markets or not also. Energy is demanded by consumers, but the reactive power is really only demanded by the natural monopsonist ISO so they can maintain the stability and reliability of the grid. It is an important service and we've heard that the ISO doesn't have appropriate access or appropriate incentives to make it available.

However, it's not the same as mutton, because the consumers aren't demanding it. Is the real question a tradeoff between the ISO trying to require resources in a non-market way, versus a created market using a vertical demand curve? The hope is we'll have a competitive market and reasonable rates will emerge for reactive power, and maybe we'll achieve cost savings of 3-4 % if we're lucky.

I'm not sure whether the cost savings are obvious here, of if the analogy really works. At the same time, if not a market, then what?

Speaker: The ISO isn't the only entity demanding reactive power. A steel power operation uses reactive power when they turn on their furnaces. Any electric motor uses reactive power. Most manufacturer are consuming reactive power.

Some manufacturers have reactive power equipment onsite to lessen the burden on the system. Reactive power is needed by more than the ISO. All the assets on the grid use or produce real or reactive power.

Comment: Yes, but most consumers don't know how much reactive power they are demanding. That doesn't fit into a market paradigm. A market participant needs to know what, and how much, product they are buying.

Speaker: As an undergraduate in the dining hall, I may have been eating mutton without knowing it. We used to call it mystery meat.

Question: I want to address the point made by Speaker 4 concerning the sound of one hand clapping, and the issue of generation, distributed resources and demand response. I'm very taken by that model. In the Northeast siting of generation and transmission is extremely difficult. There's a three way approach to the problem: generation, transmission, and demand response. However, speaker 2 pointed out the difficulties for making the market pay attention to transmission. There may be similar problems for your proposal. How can we avoid some of these pitfalls?

Speaker 4: One of the big problems is how to make this happen politically. The best approach is to look at this incrementally. If we think about LMP back when Schweppe came up with the idea of nodal pricing, no one would have thought that LMP could be implemented. Many said that there would be cost shifts and other major problems that would make it impossible. The same arguments that are being made about this proposal to take LMP down to the distribution level. It's an issue of remembering that it took LMP a long slow road to acceptance. If we're clear about why we would want to do it, it makes sense to extend it further. Certainly, it is a political process and there are going to be people standing in the way.

However, the megawatt mile method that we propose doesn't fully load. This mitigates it so that we're not really slamming people based on their location. Locations may have occurred by historical accident. It's best to ease into that slowly, perhaps even with nodal pricing too. It is important to get people those signals so they understand the impacts they have on the system regardless of historical accident of their location. Remember that there will be political buy-in from customers who are in the right place. They're going to see their bills go down. Why should they be subsidizing those other folks? There will be both winners and losers in the political process.

I also want to discuss reactive power in markets. In the UK, National Grid addresses the ancillary services problem via long-term contract. They have a regulatory incentive to keep those costs down that doesn't exist here. Most providers procure ancillary services via short-term markets, either day ahead or real time. Why not allow ISOs to hedge those forward through long term contracts that will keep costs down? This eliminates the need for people in real time to understand they are consuming reactive power. It's a market in the sense that there is some demand response, except it's from the ISO in the long term market instead of a shorter term market.

Comment: Reactive power has to be managed. If you do it via a market, do you ask the operator to solve that problem? That's a market but it's more of a monopoly buyer or regulated monopoly process than a real free market. This may be a good solution for this particular problem but for other situations that doesn't work . It's important to make that distinction.

Question: There's an old line from Yogi Berra that in theory there is no difference between theory and practice, but in practice there is. I'd like to ask about the advantages of transparency. In markets currently is there too much transparency, or the wrong information, or not enough information, or too much information for markets to make the right decisions?

Speaker 4: There are special situations where reviewing information at particular times can be anticompetitive. However, broadly speaking, transparency is a motherhood thing; you can't have enough. Transparency doesn't necessarily mean burying people in data.

Maybe the ISO should just calculate what the prices are for reactive power. They're there, and you can value them. If people see what value the dispatch model puts on reactive power that could be a starting point.

Speaker 1: In the PJM system in 1997, before they started using LMP, they started calculating it and reporting it. People were convinced that there couldn't be that much difference between nodes. They thought it didn't matter very much. Then they saw that in some conditions it is t $150 here and in others only $20. It gave people a chance to see the ramifications of the upcoming policy. It didn't solve every problem, but it did solve many problems ahead of time.

Speaker 2: One irony is that entry into the reactive power market is much, much easier than generation or transmission, because many reactive power devices can be put into existing substations. This makes siting much easier. In the UK, National Grid has started to put in portable tractor trailer SVCs with a static VAR compensator*:* bolt it down, plug it in, get reactive power. If you no longer need it there, you unplug it and move it someplace else. Reactive power markets have smaller entry increments which probably increases their potential. People at FERC have argued that this kind of high technology answer to congestion is unreasonable or won't work. This kind of innovation idea is not an easy thing to do but you can work slowly at implementing it. If the device is not adding benefits to the market then the ISO opens the circuit on the device and it sits there.

Speaker: The information question is an interesting one. If consumers are not getting the price signals, then they're not getting enough information or the right information. However, there are some specious arguments have been made in the past. For instance when LMP was implemented in New York some complained that there was too much information, too many prices to track, it's a black box, etc. Stakeholders don't need reams of data, they need relevant information. A customer only needs to know their nodal price, not the other 3000 prices on the EHV system. If this goes to distribution, I shudder to think at the number of prices we're talking about. But you only need the relevant information and it must be correct.

Question: The DG presentation was timely in view of the EPA mandates for DG that the industry has to face. When the revenue stream models were run for implementation of LMP in the distribution system, were standby or interconnection issues addressed? Are standby rates from the new tariff integrated in the model?

Speaker 4: In terms of interconnection, we assumed that it would not be a problem. For the standby rate, we're trying to demonstrate that standby rates for distributed generation mean they're paying to use the system. They shouldn't have to pay to use the system if they're locating DG in the right place. Instead, they should be paid by the operator because they are creating new capacity on the system. Those costs are assessed on the load – that's the recovery mechanism. Actual costs recovered with distributed generation are greater in certain situations because capacity in the system can be recovered by the loads. The traditional standby rates actually penalize distributed generation when it's providing benefits to the system. We want to change that.

Question: How significant are the DG benefits for capacity availability compared to a base load?

Speaker 4: The models examine different capacity factors. Capacity factors of 70, 80, and 100% all show it's quite significant. The issue is running DG at peak rather than at high capacity. Availability at critical times is very important. Renewables will soon be considered in simulations too. We'll do Monte Carlo draws and examine different probabilities of wind, or micro-hydro running.

Question: What about fuel costs like natural gas?

Speaker 4: Models haven't been run for a U.S. fuel cost case. Micro turbines with natural gas prices in North America probably won't be as promising. However, an interesting tradeoff here is that environmental benefits may be there even if the cost improvements from capacity aren't. Utilities will soon implement the clean air interstate rule and mercury rule. The technology is cleaner than some of the base load technologies. An operator could reduce line losses, make up for some generation, and improve environmental attributes – at that point even expensive gas might start looking good. Those issues are worth considering.

Question: I want to comment on why is it different for electricity versus gasoline. The reason is the opaque nature of electricity. If I go to a gas station and fill up my Suburban, I have choices – I can drive my Honda instead, I can take rapid transit. There's a connection between what I'm doing and what I'm spending.

If I try to read the meter on the side of my house, I have no information. It's a bunch of numbers and a dial, and it doesn't tell me what I'm paying at any given moment. In the California electricity crisis, some of the electricity turned into sweaters and some into mystery meat, and there was a huge political problem. What kinds of information delivery systems do customers need, and when do they need to know it? What kind of rate design and/or technological tools do we need so that customers can make rational, mature decisions about their electricity use?

Speaker 2: Electricity is different in the sense that you don't know what the price has been until you consume it. Southern Company has implemented experimental programs that give people prices or estimated prices a day ahead of time. Then they know what the prices are going to be on a hot summer peak day. People can program pool pumps, air conditioners, and other large load items to run so they avoid these peaks. People need the information ahead of time, that's crucial. It can happen, it's being done now. However, we don't know how expensive that is for the average consumer. Nonetheless, people can take actions, some quicker than others, to react to price changes. Unfortunately, with electricity there are large fixed costs for some of these actions.

Question: The ancillary services proposal involves specific locations on the grid that create significant market power issues. What happens with the same generator bidding into two different markets, one where they have market power. They can play off their market power in the ancillary service markets to raise their price in the real power bid market. Doesn't that create additional difficulties and a need for more market monitors?

Speaker 2: The conventional wisdom is that reactive power markets are geographically small and HHI calculations won't work in such small arenas. These markets can be regulated via market based or cost based approaches. Broadly, a cost of service type rate base obligation is a call option on those assets at variable operating costs. It may be that reserves are needed in reactive power also, same as in real power. The markets could be small cut the cost of entry into those markets is also minimal. Market entry is not nearly as expensive as building a new generator. It's not easy, and these markets will need regulation but they should be considered in a broader context; they're not just there for voltage support. If you put reactive power into the grid or take it out at certain places there's more thermal capability to move real power. It can truly lessen transmission constraints.

It's easy to construct examples where if reactive power is not paid for properly, then there will be inefficient dispatch. It means that distant power is dispatched across the transmission line whose thermal constraint could be relieved with a generator who's competing also. It's not an easy process, and laissez-faire won't work. Mitigation rules are necessary. The most extreme form of mitigation is cost of service. We certainly have to do something about mitigation.

Question: Is there a disconnect between this discussion and discussions going on in many of the states about the benefits of markets for retail customers? Many states are really considering rate caps. In many of them, interim arrangements in restructuring are winding down and deadlines for rate cap removal are imminent so they are considering new ones. Certainly, the fuel price volatility in the last year or two has resulted in unanticipated price escalation. For a lot of states, perfecting markets is irrelevant. Their agenda is to implement a rate cap without a California meltdown.

Market advocates are not communicating the benefits of markets as an alternative, even if they are imperfect. The states are going to start moving in this direction and the industry is looking at how to address a proliferation of rate cap and rate freeze proposals.

Moderator: It's self-evident that there's a disconnect. People worried about new caps should not assume there is a dichotomy between that and problems in market design. A new law and/or a new cap will not solve these problems. Rate stability is certainly a legitimate problem. These problems can be addressed in ways that are consistent, and mutually reinforcing in a virtuous circle. Other solutions and situations are the opposite, the vicious circle kinds of problems. Caps won't necessarily solve them

Speaker 1: The political climate generates changes in market design. Utilities had to sell off generation because state commissions were upset about the cost of nuclear plants and threatening to disallow costs or lower the rate of return. Utilities were happy to give up their generation business because the cost of service model wasn't working for them. We have to make the best out of these processes. Getting reactive power or transmission right are the same problem in a vertically integrated utility or a competitive market. The only issue is the way you price things. A utility that's not addressing reactive power properly is labeled imprudent in cost of service. It's just a different terminology.

Speaker 4: I agree there is a false dichotomy. Part of the problem is that markets imply volatility and cost of service implies price certainty. However, Florida Power and Light had prices go up 20% in their last fuel cost proceeding, and they're fully regulated. If we consider price volatility and hedging, do markets or cost of service regulation do a better job?

Speaker: The false dichotomy argument has not been properly demonstrated. It's a real problem if 15 or 20 states are reverting to cost of service as a way to solve price volatility. They may end up with the worst of all worlds, a hybrid variation of cost and market in a transitional mode.

Question: One thought on the political practicality of more complex pricing mechanisms and reactive power. When the pundits realize we're thinking of charging for imaginary power, the political reaction will be very interesting [laughter].

Moderator: It's only imaginary money.

Question: Maybe they shouldn't charge by the megawatt and should charge by the MVA at retail. Somebody can understand that*:* just multiply two numbers like 120 times 7 amps. Reactive power can be integrated slowly just like buying energy efficient refrigerators. This approach can get us over the hurdle of the political impracticality.

Session Two.
Forward Contracts and Capacity Markets*:* High Powered Incentives or Assets to be Stranded?

Investment in infrastructure creates risks over a long horizon. Allocation of those risks among final customers, regulated utilities, and merchant investors is a central issue in restructured electricity markets. Most of the declared benefits of electricity restructuring must flow from better investment decisions and the associated allocation of risks. A singular failure of electricity restructuring would be to create a new stock of stranded assets without clear responsibility for compensation. The post-California, post-Enron reaction to markets created a widespread view, or at least policy argument, that risks need to be shifted back to customers.

Capacity markets are being modified to create better incentives and longer term commitments for generation investment to achieve resource adequacy, with the costs assigned to customers. But are these capacity markets sufficiently reliable to support new investment rather than simply transferring money to existing facilities? Do investors see these markets as being sustainable for a long enough period to *provide a significant increase in the present value of new investment? Will purchases under these contracts remain committed, or if prices fall, will they recreate the stranded assets we thought we had left behind?*

And on the energy side, separate from capacity, what contract arrangements would be required to support investment in generation? Are traditional utility-type long-term (10+ year) purchase power agreements necessary for new investment in generation? Or could shorter term (3+ year) horizons be enough with the right mix of hedges and creative structuring? If the former, would this signal the death of a developing competitive market? If the latter, would default retail service auctions like the New Jersey BGS with its three-year forward contracts create enough buyers to support merchant generation investment? In either case, the different procurement models would interact with the details of the design and availability of long-term transmission rights. Are the developing long-term market features workable in the long-term? What long-term payment guarantees are necessary? And how long would be long enough?

Moderator.

There are many initiatives to increase the electric infrastructure. It's in legislation and regional debates, including transmission, base-load coal, and nuclear renewables. However, need for new investment in capacity markets has extensive variability and uncertainty. The requirements for capital investment, higher fuel prices, and increased environmental mitigation mean industry costs are rising when retail rate caps are expiring and rate cases are happening. The reaction out there from the public is the same as when gasoline prices hit the fuel pump last year. It's a visceral reaction to say the least.

Speaker 1.

I'm going to talk about risk today. Risk is not a zero sum game, it gets divided among players. The key is to manage risk so that there's an optimal allocation that minimizes cost and eliminates some risks along the way. However, if you assign risk to a developer, they'll charge you for it. Risk is not free. Conversely, risks can be valuable incentives. When we design markets, who bears what risks, will they be paid for it, and what are the right incentives?

There are four high level risks for developers. First is the development process. What technology to build, what fuel, location, engineering costs, and getting permits lined up. These are initial entry costs. Second are operational risks. Is the machinery available when needed? Is the efficiency strong? Is pollution being mitigated and maintenance being handled? Is transmission available? Third are external market risks*:* the weather, the rate of growth, fuel costs which can be hedged, and competitor actions. One problem in New England was that no one project was bad, but building 30,000 megawatts in a 30,000 megawatt market is not smart. No one individual made that choice. Finally there's technology risk; if someone has a better mousetrap five years down the line that makes yours obsolete.

Another set of risks are truly outside the control of most developers*:* appropriate market access, a stable regulatory and environmental policy, and a non-confiscatory political environment. In cost of service, the risks were strongly but indirectly borne by consumers through a regulatory process and pass through charges.

Thus, utilities had few incentives to manage their costs well. Organized markets have improved costs substantially. The idealized energy only market structure moved risks to generation. If your unit is not available during a high priced hour you don't get the money. If EPC costs are excessive there's less profit, and there's no pass through of any of these costs.

Consumer risk in the market model is minimal. Now, in a market environment fuel costs can pass through. If growth is fast and development is delayed, there will be higher prices. If technology improves, consumers benefit and vice versa.

The problem is that developers and financiers are unwilling to bear too much risk. The current political and regulatory uncertainty in organized markets means that no one will build merchant. They won't build a quarter billion dollar power plant on spec. The critical problem is the lack of a counter party to buy power long term. Retail deregulation is responsible for this in part. In New England most utilities are prohibited from being a counterparty by law. In New York there's no prohibition but a strong reluctance because there's no guaranteed customer base, and no liquid way to resell capacity contracts in a market.

These contracts may move too many of the risks back to consumers. Long-term contracts leave customers with substantial risk in technology and fuel choice, quantity, and cost structure. If those things are wrong consumers have a large stranded cost again. In New England, consumers are still paying down millions of dollars in stranded costs from regulated ownership. However, contracts are not as bad as cost of service, because a lot of the risks can stay where they belong, with the developer. They can get EPC costs right, or timetables locked in under contract. However, many of the biggest risks are still going back to consumers.

Another issue is whether contracting is mandatory. Who is the counterparty? Investor owned utilities will look for a regulatory backstop to ensure that they don't have stranded assets with no recovery mechanism. Competitive LSEs have little incentive to contract without a mandatory must contract rule. The incentive is to underhedge, because extra options are hidden in the system. If prices get too high they can dump customers, and the provider of last resort has to take them. If you don't like high market prices there's a pretty good regulatory hedge that those prices will be lowered. That happened in California.

New Jersey has the three year rolling BGS auction. It's great except for the three years - who builds power plants for three years? However, there is a sureness there that's missing in other markets. There will be another three year contract, and someone else will need the capacity. I'm not convinced that it is a complete solution.

Mandatory contracting, or strong incentives for these contracts may be the solution. A market for capacity bilaterals is needed because load shifts, conditions shift, plants get built, ownership structures change and they want to sell the contracts. The contracts you could imagine with power producers would be idiosyncratic; long documents with covenants, special terms, and articles that address the fact that power plants are not fungible. A liquid market for a non-fungible product is difficult. We need standardized capacity contracts similar to energy contracts that can be traded easily. Finally, a counterparty or market maker is needed who can insure there's no daisy chaining of counterparty risks.

If we're doing that, why not have the RTO be the market maker? It has a similar role already; it knows the context and the players. They have to define the product because capacity has to be locational and they know the relevant locations. If the RTO is running the market, with power plant and performance information, it allows for creative incentive design. It can move appropriate risks to generators to be available, to be located appropriately, to be operating efficiently and meeting contractual obligations. This allows for automatic balancing across LSEs, which reduces the transaction costs. If they lose a major customer, they don't have to find customers for the surplus capacity. It moves as the customer moves, with the RTO as the counter party.

Are capacity markets necessary in addition to a lot of contracting? A capacity market will have a lot of bilateral contracting underneath it. It will serve as the spot market. Just like IBM stock that's not actively traded on the New York Stock Exchange. Capacity markets can do a lot of useful things. They place development risk on the developers who are buying the most efficient units and putting their money on the line for developers, not for customers. Inefficiencies and risk belong to the developer. A well designed capacity market augments the energy market. It replaces incentives that have been blunted by price gaps.

The new capacity markets have an implicit weather hedge. If there is a year with low energy prices, the capacity payments will be higher. In a year with high energy payments, because LMPs are just naturally high or otherwise, the capacity payments go down.

This allows energy only markets to have price responsive demand. The clearing price can be set higher than $1000 more often because investment is being encouraged. The capacity market is a net against the energy price; as energy payments go up, capacity payments go down. The capacity market's importance in the market can diminish over time. However, if the energy markets are still dysfunctional, there's a mechanism for capacity and reliability.

The New England design is a forward capacity auction, it will be procuring for three and a half years before the power year and the obligations. The ISO will act as a gatekeeper on the market. If 20 developers come rushing in, the ISO will prioritize which products best fit their reliability needs and lowest cost.

This eliminates the boom-bust syndrome and reduces that risk considerably. It removes the risk of building a plant, realizing that 20 other folks had the same idea, and everyone loses out.

ISO New England is technology neutral as much as possible. A bricks and mortar generator, or demand response provider can participate, as long as they control the amount of load or the peak load.

Close linkage with energy markets is important. Minimizing initial administrative parameters is critical for regulators. It matters that cost of entry is realistic, and not just determined by a consultant. Or let market bids set the market clearing price as they're doing in New England. Any initial parameters should respond rapidly to the market.

One question is whether markets are short or long term. The short run market was a hard sell in New England despite New York's adoption. It gave the perception that too much capacity was being obtained. Some felt it only pays for what's there, as opposed to paying people who want to come into the market. New York has no link to the performance of generators in real time to whether or not they're going to get the capacity payment. By solving these three problems in a long run market, we actually have the majority of the states signing on that this market design is sensible. And I think, as a consequence, we will have the political stability to allow developers in New England to build with a fair degree of confidence in the stability and longevity of the market design.

Speaker 2.

I will present two case studies of project financing. One is the development of the Longview facility starting in 2001. It is a coal plant in West Virginia. It's taken until 2006 to do it. It was originally proposed in response to anticipated spikes in the price of gas which were foreseen correctly. It's in PJM, in a liquid market, and was originally conceived as being a project in a merchant environment. That is not the case now.

In order the cover the high capital costs of a coal plant, the facility was sited at a mine; taking raw coal from the mine straight into the power plant. The plant was designed to take unwashed coal. This created a 20% savings, in addition to the elimination of transportation costs, which are considerable component of coal generation costs.

It was originally going to be quickly developed, online early. The developers actually slowed down construction from 2001 until 2004 because of the market problems during that period. It's a $1.4 billion facility; a 610 megawatt pulverized coal site. It's in Morgantown, West Virginia, which is a college town. That's one of the reasons why they've had difficulty. Several college professors argue this technology is not the best. They made the decision to go with pulverized supercritical technology because IGCC [Integrated Gasification Combined Cycle] plants were, and still are, an unproven technology. They use acid mine water from flooded Pennsylvania mines for cooling purposes and makeup water, which has added environmental benefits.

In 2004, they began a formal RFP process to finance the facility. The merchant market had disappeared, so they started a "reverse RFP" and contacted all kinds of people. There was relatively strong interest, mostly from investor owned utilities. During the RFP process, it became evident that the IOUs were fishing for information more than anything else. Municipals had interest, but it's hard for them to make decisions. There are time consuming committees, they don't contract efficiently.

They are now discussing 20-year contracts with two munis in PJM West. A contract is probable after construction starts. It's difficult for munis or others to analyze a development project seriously if an undercapitalizer or a development company without deep pockets is involved.

However, in September, 2005, they were contacted by several investment banking firms and banks with trading desks. They indicated the project could start construction with short term hedging arrangements. They solicited bids and hired Goldman Sachs as private equity placement agent, and then Goldman Sachs and West LD, a German bank, as arrangers of their debt. They're now raising money. The EPC Price has increased so that the project will be closer to $1.5 billion, because of price increases and international steel costs.

They're looking at $450 million in equity and $950 million to $1 billion in debt. Currently there is a convergence of different factors. One is the emergence of these hedging strategies. Second, most of the equity companies have never made investments in the energy sector. There are 30 companies interested once the last permit is received in May '06. Most of them are private equity firms and hedge funds interested in higher returns. They've had difficulty in auction processes; which drive the price of energy assets down. This being a green field, they feel that higher returns bring greater risks.

I'm not qualified to discuss the details of these hedge deals, they're beyond me. Suffice to say that by putting the hedge in place, the lenders are satisfied that the hedge provider is credit worthy enough to service the debt. That's how the facility will begin construction.

The equity participants draw comfort from the fact that pricing in this liquid market is rising, and the spark spreads between gas and coal are widening. The trend lines are upward. Some consulting reports done by lenders show good prices until about 2017.

Another case is PRB coal, Powder River Basin coal. They have a strong EPC contract with a well known joint venture. They have a long term coal transportation agreement, not a supply agreement, which is different than Longview. It has similar hedging strategies, although it's a gas hedge and not an electric hedge. 30% of PRB is sold to a group of munis. This kind of real financing can be done in this market.

Comment: Who bears the risk of a carbon mitigation program that might be implemented on a national level.

Speaker 2: The project would, itself.

Comment: In that case do the economics still look as promising?

Speaker 2: Yes. If the projected market pricing is realized in western PJM and the facilities are financed by the term B type financing, there are 50 to 100% cash sweeps in the early years on the debt. After five years of operations, the models show that $600 of the $900 million in debt will be retired. At that point, the project is viable enough to address emission issues. That's the analysis so far.

Comment: To clarify, these projects have a fraction under long term contracts, different in each case. The key issue for both of them is that the unique hedging mechanism is common for each; four and five years respectively.

Speaker 2: That's right. However, there is a balance between the kind of debt that you can put on the facility and the amount of long term contract.

Comment: The hedging counter parties are not final customers, they are marketing intermediaries, right?

Speaker 2: Yes. They're financial institutions. This gets the largest bang for the buck. The way they're able to do these hedges was very surprising for the developers. It's because there is liquidity in the gas markets as far as the 2010 time frame. People are buying and selling gas in that time frame for seven, eight, nine dollars; the correlation with energy prices is direct. They guess what the price of energy will be in that time frame, and make their bet.

Speaker 3.

I'm going to focus on a company that pursued some interesting opportunities within the deregulated industry and became a premier demand response solutions provider. The goal was to focus on issues that aren't of core importance to customers. Managing energy isn't core for a hospital, grocery store, or a university. If an outsource provider can provide value, it's a market opportunity that can be capitalized.

They focused initially on the demand response market. They found it very appealing because it's an immediate resource for the market. The approach doesn't require a lot of up front capital or a lot of research and design. Only enough expertise to make it differentiated and have a competitive and distinct advantage.

Later, they segmented the demand response market into two categories. There are three categories they identified. Demand response for price based demand response, aka economic based demand response. They did not pursue this model. They worked on alternative capacity resource for the market. This is demand response, changes in behavior, changes in electrical consumption, in response to system resource capacity needs or system reliability events. Third, they focus on connecting backup generators to the electricity grid, providing automated means for load curtailment at 400 or so commercial and industrial sites throughout the country.

They now have over 200 megawatts of demand response under management and over 500 megawatts of peak demand currently monitored by their software system. The software allows for real time communication and control of customer assets at a variety of commercial and industrial sites throughout the nation.

Their approach was to get the attention of the facility managers or CFOs and offer a fully automated, hands-off solution. This meant not only demand response but full demand management, data management. They do research, education, permitting, financing, and metering. They have the technology application, manage payments, and do the curtailment.

They bet that New England would be the most appealing market for this approach. They responded first to a gap RFP in southwest Connecticut. The ISO was looking for 300 megawatts of quick start emergency generation to address one of the most capacity constrained regions in the United States. The ISO wanted to ensure they could avoid rolling blackouts and reliability events for the next several years. They bid with 34 other companies that encompassed new generation, conservation, and other demand response projects.

They were one of six companies awarded a four year capacity contract for 30 megawatts, now 33 megawatts. 90% of the megawatts that were awarded were demand response megawatts. The ISO had some experience with the company and their approach from 2003. It was confident they could count on them and that they would look, feel, walk, and smell like generation. The system operator could press a button and get instantaneous guaranteed curtailment. ISO New England was a big demand response proponent.
The company is now operational in the New York ISO as a responsible interface party. In PJM market as an emergency demand response

provider, and the Cal ISO where they provide demand response in the demand response partnership. They also have direct contracts with Southern Cal Edison, National Grid, and NStar to do demand response work for them.

They've had considerable growth and some success creating a market for demand response that didn't exist previously. Out of 120 commercial and industrial customers, probably 60% to 70% have never participated in real time electricity markets before they were contacted. This includes universities, retail chains, lodging and resorts, light industrials, and hospitals.

This approach provides a real capacity resource. If it's done properly, it can be an account honorable resource. Since they are focused on the reliability aspect of capacity, every time there's an audit called, their system has to work. There have been several simultaneous events in multiple markets, for instance July 27th this past summer. Even in those cases they've been able to provide and prove the proper load curtailment.

Some of their clients may have up to 50 sites that can instantaneously be curtailed when the grid calls for an emergency command response event. One client can take over 12 megawatts of load off the grid. A university customer has five separate sites providing 370 kilowatts of load containment. Simply changing air conditioning, lighting; using the system to provide this reliable, measurable capacity resource.

An important part of this strategy is they're contacting utilities and system operators and letting them know that this approach is available for capacity constraints. Demand response can address a number of other changes this panel and others are discussing. For instance, it can solve the lack of long term agreements, and fill in those boom bust cycle gaps that occur because of market risk. Demand response is a perfect gap filler. They generally need only a three to four year capacity agreement. It's an important role that can address peak electric capacity shortfalls. Demand response is not a substitute resource accepted at peak; it's about more efficiencies in the market. DR is a capacity alternative that is economically and operationally viable.

It also complements existing energy efficiency programs that might exist. It's a catalyst for future energy management and efficiency measures. This approach turns non-active institutions into active participants. It helps commercial and industrial companies understand their impact on the market.

They also help utilities become more innovative participants. They conduct a thorough market analysis with the utility and then design a program that is implemented and tracked; capacity on demand. It competes with generation and complements it.

The programs can be significant. A 100 megawatt capacity agreement is often large enough to retire a large peaker in a region. That can create tremendous efficiencies in the market. The price is usually $10 per KW per month, competitive with other solutions in the market. It's cheap enough to encourage adoption and terms can be from 3-6 years.

These kinds of programs can be implemented quickly. In six weeks, over 100 megawatts of new, additional demand response was aggregated and brought to market in response to a recent ISO New England call for winter response. That includes new multi-year agreements with customers, installation of equipment, and enrollment in the ISO's program.

There are key components for this kind of program to successfully play in the market. Three to five year capacity agreements have to be allowed, measurement and verification in real time technology component. A locational component is critical. A level playing field, so that when RFPs get released, they can compete against generation and other types of projects. Finally, demand response is a broad category without a broad understanding. It requires understanding of different types of demand response in different markets. For instance, one RFP is asking for multiple megawatts of 5 to 10 year demand response contracts that's available from 8 am to 8 pm. While this is a level playing field involving reliability, it's not reliability at peak. Peak doesn't happen from 8 am to 8 pm, it happens in windows. That's a different reliability product.

Speaker 4.

I'm going to discuss development incentives in a market with untapped spot energy prices and forward contracting to protect against spot price volatility. This creates incentives and creates more capacity while avoiding standard investment. Second, I want to discuss an appropriate calculation of risk. This will include a discussion of the mismatch between developers and buyers, allocation of risk, and risk hedging. I'll also discuss how the process of hedging discovers the market.

The term "energy only" is bit of a misnomer. It really means market design relying on a well-structured spot market with day ahead and real time prices, locational marginal pricing, and well-considered price mitigation rules. It also includes mandated forward contracting for load serving entities to address credit adequacy standards and a full transfer of risk. This holds even if caps are adjusted, raised or removed. The most efficient market is designed to ensure reliability margins are met, to protect buyers from extreme price volatility through forward contracting, to insure reliable supply, and to create capacity investment at the right level, mix and locations.

Here are some basic market realities. Customers are price takers therefore risk takers. Planning and construction horizons are extremely long and there's no significant incentives to shorten them. The regulatory guarantee of a fair return puts risk on customers. This creates the situation where sub-optimal plant mix can exist for long periods of time at customers' expense. It creates perverse economic outcomes and price signals.

One of the big incentives in regulated markets is managing the regulators. In contrast, a competitive energy only market means market accountability where the spot market defines prices, forward contracts define the longer term forward market, and form the basis for hedging strategies for investors and developers. The market can dictate the quantity, mix, and location of generation capacity. It distills supply/demand balance into a planning signal called long and short term price through forward contracting. The risk in this structure lies with the sellers who then hedge that risk. The risk hedging is what creates an explicit link between development, investment, and market price.

The mismatch between buyers and developers has to do with contract length. Load serving entities contract to buy shorter tenure, two to three years, and smaller sizes. They want a competitive price at low risk. Developers generally want to sell long tenure, investment recovery at eight to ten years. They want larger sizes because of economies of scale. They want a fixed payment per month that's not dependent on how often they run. They want a certainty of return with low risk, and a contract when prices are high.

A financial institution, an intermediator, can manage this mismatch and the associated risk. They handle the price, credit, and operational & dispatch risks, including efficient dispatch into pool and payments from a pool. This matches expertise and functions very well. Developers should build and operate plants, the financial institutions should manage risk. The market should allocate risk in quantity and type to entities who are prepared to and able to bear that risk.

This risk hedging can create an explicit market investor bridge. The initial risk in this structure lies with sellers, who want to hedge. An intermediator can approximately double the length of forward contracts in existence. Mandated forward contracts of three years can be doubled to six. This could increase to eight to ten years soon. The hedges can be physical and/or financial, and can be modified easily depending on specific situations.

What does this process look like? Let's consider a developer who wants to hedge a gas-fired intermediate project in PJM. They approach an intermediator who would sell to the LSEs a fixed price as a metered forward contract, or a bundle of forwards, at a price of say $70 per megawatt hour for three years. That covers the forward contracting piece with the load serving entity. At the same time, the intermediator sells the developer a toll tailored to the characteristics of the plant they want to build for a term of six years. A "toll" means they would purchase the right to deliver gas to the developer at a price in dollars per KW month to the plant and to receive electricity in return at a specified ratio; the heat rate.

Let's assume a 7 heat rate toll and the financial folks are willing to pay $7 a KW month for that toll. This means that a 7 heat rate gas plant with a gas price of $7 per MMBTW, which they can hedge far in the future, would have a running cost of about $50. A 7 heat rate times $7 is $49. Throw in a buck for variability and it gives us a nice round number of about $50 per megawatt hour to run that plant. If a 5 by 16 forward product in that market during that time period is about $70, then the capacity piece is the difference between the market price of $70 and the running cost of the plant at $50. The difference is $20. $20 times 340 hours for a 5 by 16 product divided by 1,000 comes to almost $7 per KW month. The capacity in energy markets are consistent with each other.

This example is a 200-megawatt plant. The developer has now contracted a revenue stream of about $1.4 million a month or about $17 million a year. The developer is hedged with a fixed revenue stream for that six year period.

What happens during the six year period? If prices remain stable, the developer may investigate further development since the prices were sufficient for this original investment. If they seek a new hedge with the same price signals, the forward market may support that investment or the developer may find that further investment isn't needed or a smaller amount of investment is needed. In either case, subsequent development will be stimulated by the then-current forward market prices.

The developer will almost certainly look for opportunities or continue to extend their existing hedge each year. They don't just hedge their plant for six years, store the contract and forget about it. The market is evaluated each year, and if it makes sense the hedge is extended. If prices have gone down or softened they may wait a year or two to extend the hedge. No matter what, they maintain a 3-6 year period of a hedged contract with fixed revenue flow. That's essential to a developer.

If prices go up over the six year hedge, the developer may invest in another project because incentives are even better. They would certainly want to extend their existing hedge at these higher forward prices. Other investments would also go forward in this situation. As each subsequent investor moves forward by hedging their investment, the forward market that provides hedges will see price adjustments for subsequent hedges. The forward market and associated hedge prices will achieve equilibrium and market saturation.

Finally, if prices trend downward during the six year hedge, then hedges available to investors would no longer support further development. As developers and investors continue to look for development opportunities, while intermediators continue to look for hedging opportunities, the forward market is continually being discovered. Existing hedges are dynamic not static; the holders of the hedges continue to extend them periodically. This feedback process tends to stabilize markets over the long run at the right level of investment. Mismatches between supply and demand are minimized.

Certainly the market is not perfect this way, just optimally managed. Recessions are a possibility. Investment is still somewhat lumpy. However, investors are probably smarter now than they were. Ultimately, the financial service providers take the risk.

Question: Your notes indicate that the hedge will also be supported by first lien on the asset. This makes business sense to me. However it will be done with an "unfunded synthetic letter of credit." I don't know what that is.

Speaker 4: The project finance guys wrote that and I don't know the answer.

Question: The intermediator's financial tools use the liquidity of the gas market to back up these long term options. Are they using participating swaps, things of that nature? How does this work?

Speaker 4: The market people combine bundles of transactions on each side of a particular arrangement which create the hedges that they need. But the specifics of the hedging are beyond my involvement. They can hedge it by a fixed price sale to the LSEs. Beyond the three years they look to the liquidity of the gas markets and other secondary hedging options. They continue to hedge through the three year period. It doesn't matter to the developer. The problem belongs to the financial institution.

Question: This last question is important because of mandatory requirements. There has to be some buy-side in this market, for instance the mandatory requirements for the LSEs. The New Jersey system has the three-year horizon. How is that transformed into six years, especially with the lag time for new plant construction. Just how does this work?

Speaker 4: I don't have the specific details. The financial service providers have made this work with other commodities, often with similar circumstances. However, I don't have a definitive answer with specifics.

Question: There are some concerns. One is the prerequisite for mandatory contracting. This is done in some areas, but there are some non-jurisdictional entities inside these ISOs. Who imposes a mandatory requirement on them? How are those requirements enforced or monitored? We can't impose them on municipals. If capacity markets are run through the RTOs, their tariff provides the backstop we need.

Second, is the link between physical plant and responsibility to the LSEs broken through the role of the intermediator? If the system needs to back up real load with real capacity and have a physical requirement, then a tracking mechanism is needed that can ensure the megawatts are on the system despite any sophisticated financial hedge. Liquidated damages contracts have to have real plants, so the system works properly.

Speaker 4: The jurisdictional issue is important. The primary enforcer would be the state regulatory agency. In New Jersey, the percentage of LSEs under forward contracts is high. These contracts can happen even without being mandated. In less advanced markets than New Jersey the issue will need to be addressed.

Second, is firm LD [liquidated damages contract] as good as a physical plant? It's better. The obligation, responsibility, and incentive to deliver under a firm LD contract is greater than a standard physical delivery situation. If they know that failure to deliver means they have to purchase from the market and make good, it's an enormous incentive to keep a plant on line. More so than a proportional claw back of a demand charge if you fail to deliver.

Question: My question is directed to the third speaker. You described how many folks were new to demand response. This was surprising because New Jersey requires that anyone over 1250 kilowatt hour peak load be on hourly meters and many of the customers described are based in New Jersey.

Second, you stated that energy efficiency programs serve as a catalyst for further energy management and efficiency measures. Do you have further information on this? This unintended positive collateral benefit seems significant. When customers are on hourly meters they address demand response and then improve management skills. I know of one large chemical plant company in New Jersey that claimed it cut its load by a megawatt a year.

Speaker 3: I appreciate that, you're certainly preaching to the choir. The market is ripe for measurement and better management. A key part of these programs is the installation of a real-time energy information system.

The New Jersey mandate for interval meters has not been enough. The facility manager might have some data and tools but it's not the same as an active, participatory role in wholesale markets. This requires price feeds on a real-time basis and other more detailed information. Second, a demand response service company can come in as a manager with expertise that a facility manager does not have time to develop. These kinds of companies can show them why and how they go from 54 megawatts worth of baseline to 63 megawatts of peak demand. Analysis can help them determine if that peak can be moved to another time. Extensive analysis is necessary. It's a combination of sub-metering a company's processes and also knowing what the prices are in the market. Most companies get a bill similar to a residential homeowner's, except it's $300,000 for the month. Nowhere else in an organization do they spend this much money while knowing so little about how it's spent. It's a training wheel strategy.

Question: Let's discuss some demand response issues. When an operator needs capacity, they call in a generator or call on load to respond. In either case they are paid. However, if they call on load and pay them it's called an emergency and it makes the national news. Even in the context of Demand Response management, it's done "when an emergency is called." It's always relating to that bad thing.

Second, these new customers who are candidates for capacity payment when they respond, are the same load that an operator relies on in multiple contingencies. They the easiest to call on and get a response that's large and meaningful. If this kind of demand response approach is promoted, the best candidates for real emergencies have been removed. There's not enough left for serious contingencies that could cost thousands of homes to trip. It's good to get demand response but the kind of big customers needed at a higher level of contingency are not available. How does this all work?

Speaker 3: We need to recognize what demand response can and can't do. Demand response is not a substitute for all capacity in the market. It is a resource for a peak, a portion of that market. It is used to address a certain piece of the market. There's a difference between capacity markets and reserves markets. Demand response can be an active participant in the reserves market. In the capacity markets this model focuses on addressing those peak needs ten times a year. Currently, we do build churches just for Christmas and Easter when it comes to the electricity market. We've overbuilt our capacity resources unnecessarily if demand response to peak can be implemented. Further, we believe these kind of resources are 5% of the market, not 1%.

Question: That's a very important point to recognize, that they are not exact substitutes. However, a lot of regulators don't realize that. The necessity to be clear about the two is important. Second, even if it's 5%, you can't restrict how people will use it. Once you make it available, it's available.

Speaker 3: It's important to clarify how this resource is going to be utilized. For example, California is a challenging market with a program called the demand response partnership, the DRP. Their contracts for demand response companies specify when those resources are supposed to be used and how it should be called. It's very specific.

Question: For speaker 4, I don't understand why your model needs required contracts. The financial company is hedging the second three years of the six year deal, they are locking in an out payment of six years but only locking in revenue for three years. Obviously, they have a way to hedge the second three years. Why couldn't the same hedging technique be used for the first three years? They don't need that guaranteed contract, they just need forward markets.

Speaker 4: The reason for mandating forward contracts from the LSEs is concern about protection. If spot prices are going to be uncapped, LSEs and in-use customers need protection against extraordinary prices. Mandating forward contracts creates a protection mechanism. If an LSE has hedged up 80% of their load with forward contracts, then spot prices can scream for a period without major financial consequences. If they haven't been required protect themselves in this way, they pursue a "regulatory solution." They look to regulators to mitigate prices by fiat.

After an initial period, the market will realize that having forward contracts to hedge risks against uncapped, spot market prices is a good idea. The mandate is only necessary for an initial period, the market itself would do it on its own. The New Jersey market has already done that to large degree without a mandate. The spot market should be able to operate without caps on it but with some protection from a series of extremely high prices.

Question: What is the cost to the intermediator for the first three year hedge with the regulatory back up, the mandate, versus the three without? Is there a premium?

Speaker 4: Absolutely, if they take risks, they charge to take that risk. It could be done without the mandate for forward contracts, but the hedging cost will change substantially.

Question: Yes, but risk never goes away, it's just being pushed around somewhere. The regulatory mandate doesn't make it go away.

Speaker: Yes, but it's being pushed to risk management entities who make that their expertise. The entities who want the intermediator role are extremely competitive. The financial service houses will provide highly competitive risk premiums. They are highly skilled and the overall environment is competitive – this keeps those risk premiums low.

Question: Uncapped, spot markets have been discussed several times. However, one doesn't know what they've paid until after the fact in these markets. We cannot have uncapped spot electricity markets. You can set a very high cap, but uncapped means a billion dollars a megawatt hour price is possible. This may just be a semantic issue but it's worth clarifying.

Speaker 4: At the consumer level absolutely, but I'm talking about at the LSE level and higher.

Comment: If we take reliability standards seriously, there's no way for capacity contracts in the energy only market design to actually hit a target without mandates. They'll hit a target driven by expressed economic desires. Until we are confident that consumers can express real demand response and that reliability preferences are being expressed in the market, then state regulators should set adequacy targets with an enforcement mechanism.

Question: For speaker 1, there's a question about non-jurisdictionals being captured in the market. In an energy only market, is there a way for the non-jurisdictionals to escape?

Second, are U.S. demand response companies looking at European markets where the demand side can bid in the day ahead market? They can also bid blocks where a large industrial customer may decide whether to run or cancel a process based on eight hours of continuous service at a certain price. Is this plausible in the U.S.?

Speaker 1: If we let markets run as energy only and let reliability be what it is, then there's no problem. If an assured level of reliability set by policymakers is necessary, then that policymaker needs jurisdiction to ensure reliability resources. Currently, FERC and the ISO tariffs are the only mechanisms that can do that.

Question: In the energy only model, there's some $10,000 prices. Those incentives wouldn't sweep up non-jurisdictionals?

Speaker 1: It depends on whether you want to enforce a particular engineering reliability standard. If that's not important, then the jurisdictional issue is unimportant.

Speaker 3: International markets have been looked at. Some companies have bids on international projects. Currently, these are young national organizations just getting started in a market with immense challenges. The mix of regulatory uncertainty and challenge create a strong need to be regionally focused. were you talking about some of the Scandinavian markets, specifically?

Comment: They are several power exchanges in Europe, where companies can bid blocks.

Question: Good capacity market design requires close linkage with the energy market. With the three year forward contracts, are there special issues in linking to the market in that forward time frame? Second, do these models use the peak energy rent reduction, or just a simple a day ahead offer?

Speaker 1: First, anything that's a capacity resource needs to be bidding into the day ahead market. That's standard. However, the model I was discussing was the peak energy rent reduction. The economists say it ought to be beneficial to have an ex post accurate deduction for peak energy rents, because then you bid into the capacity market, you are all in revenue requirement if you are a peaker and matching the benchmark unit. The peaker will get the payment, through the energy or the capacity market. They don't have to guess what the energy market will look like three years in advance.

The commercial people believe they can hedge their energy risks though sophisticated financial markets, and don't like having this hedge put into their portfolio, which they might need to cross hedge. The theory versus practice issue at work. I suspect people will get used to it; the traders will adapt to it.

Comment: So, in the case of the three year forward, it's an auction for the capacity with real units, and then you're making an assumption about the energy market price three years forward.

Speaker: No. When it comes time to pay, the capacity payment they would receive would have a deduction for peak energy rents earned in the previous twelve months. It would be one twelfth of the previous year's peak energy rents, based on real time prices. There's a direct linkage to payments and performance. If the energy market throws off a lot of money, then there's a large deduction, but presumably they've earned that money as a capacity resource.

Question: One other question. With New England's three or four year capacity option, is there another mechanism closer in time; a month ahead, or seasonal?

Speaker 1: They'll be similar to the PJM structure. There will be annual reconfiguration auctions to take the entire year. There'll be season reconfiguration auctions just before a season, and monthly reconfiguration auctions in each month.

Session Three.
Market Monitors*:* Dealing with Bad Guys, Bad Rules, or Both?
What Powers Should they Have and How Should They be Exercised?

Market monitors have been busy in the organized regional markets, and FERC's market oversight applies nearly everywhere. The market monitor is a regulatory and institutional innovation of electricity restructuring. Broadly, there are three tasks. The first is to monitor, literally to collect information and watch developments. Second is to take direct action, to the extent permissible, to mitigate behavior when a problem occurs or appears imminent. Third is to analyze the market and make sure that the existing design is adequate and functioning appropriately. There can be a strong overlap of these functions.

Conflicts may arise where bad design makes good behavior either less likely or even counterproductive, and where allegations of bad or inappropriate market behavior are disputed. The powers and duties of the monitor have varied among the regions. In one case, for example, where a generator is in position to dictate or manipulate prices, the market monitor has the power to substitute a reference price for the *price actually bid by that generator. In another, the monitor substitutes a bid cap for everyone. In some circumstances the monitor can do little more than report the problem and lacks any immediate remedial powers.*

What should be the balance of activity for market monitors? Should monitors emphasize the search for individual bad behavior, or focus on systemic problems of market design? What is the optimum role for the monitor and what powers for enforcement or market reformation should the monitor possess? What should be the primary focus of the monitor and what tools should be provided to accomplish the mission assigned? Is the market monitor mandate adequate, and do the powers meet the challenge of the responsibilities? How well are market monitors performing? What has been the impact on the market? What is the future of this regulatory and market institutional innovation?

Speaker 1.

Ideal market monitoring units should have well-defined goals, adequate resources, good incentives, clearly defined parameters and bounds, and a clear well-defined reporting relationship with FERC, the states, and the RTO. Understanding market monitors requires and understanding of institutional contexts. A key piece of that is FERC. A fundamental concern for conceiving of institutions is understanding their goals. The goal of FERC is just and reasonable rates and they have final enforcement authority in these matters.

The RTO lies between FERC and the market monitors, There are several relevant goals for an RTO. One is competitive wholesale power markets and everything that entails. The real institutional incentives facing an RTO are institutional growth and survival. It's important to think carefully about the political economy of RTOs as an organization. One result of this is that there are potential conflicts between the goals of an RTO and a market monitoring unit.

Generally, the goal of the states is competitive markets, low rates, a benchmark for success of regulation, and addressing any market issues that affect their jurisdictional customers. When we say states, we generally mean the public utility commissions.

The goals of a market monitoring unit are multiple. First, high quality analysis of market issues that are available to all market participants, and all those interested in the markets. Second, highly focused behavioral mitigation on market structure participant behavior, and market impacts, using real time data. The ultimate goal is competitive market structure, competitive behavior by market participants, and competitive market outcomes. Easy to say.

Market monitor independence is critical to their efficacy. This is critical regardless of whether they are internal or external. There are real pressures on internal market monitors because they are employees of the RTO. There are equivalent and even stronger pressures on external market monitors. Contract renewal is one. Second is consulting with different kinds of market participants and the corresponding conflicts of interest. These issues are not that complicated and there could be better institutional arrangements without radical change.

Market monitors should be subject to clear rules, established and enforceable by FERC. There should be direct reporting to the commission, not just to the staff. , There should also be reporting as appropriate to state commissions as well as state commission organizations like the one in PJM; OPSI. Informational reports should be released as they are no but without the RTO having veto power. There is a strong value for internal market monitors because they have immediate access to information and an active exchange of ideas but an RTO veto goes too far. The process needs to be transparent and available to all market participants. It should lead to open debate that includes RTO participants, regulatory agencies, and an ultimate decision by FERC. They should be basically analytical involved in discovery of information that is provided to FERC.

The market monitoring unit function has to be considered within these institutional issues. Monitoring requires specific focused questions and a point of view. The goal of competitive market structures, behavior, and outcomes shapes that view. Its benchmarks are shaped by that, and are a subject of debate, discussion, and perhaps resolution by FERC.

Monitoring includes market design. Behavior takes place in a hugely complicated context of operating agreements and tariffs. They are hundreds of pages of detailed convoluted rules for participants with billions of dollars in play. Often, those participants don't understand them despite the money involved. Detailed rule proposals from market monitors are an appropriate part of their function.

The PJM monitor has recently examined the merger between Exelon and PSE&G. They examined market power HHI measures in a real network context. This is not a normal feature of these analyses but it should be. Monitoring is looking at participant behavior in detail; markups hour by hour, minute by minute. The ultimate test are the market outcomes, not just prices and congestion but broader metrics like a net revenue system markup.

Market monitoring also must include the RTO itself and how it affects markets. The actual rules aren't in the operating tariff, they're in the software. It should be subject to scrutiny. Market participants need to be confident it is producing the outcomes intended by the rules. This assures market participants that behavior is confined by rules, and not reflecting the exercise of significant or personal discretion.

An internal monitor is probably the only organization with the goal of, and the ability to get at, these issues. Monitoring shouldn't include discretionary enforcement actions or market interventions. It shouldn't set prices. Monitors generally can't and shouldn't set offers, although there's an exception.

They should not set reference prices. This is inappropriate, they should not be telling units what they should have been bidding. Units should submit cost based offers themselves based on their own facts and subject to verification. Monitoring does mean identifying those who are not abiding by the rules, or acting within the rules to exercise market power.

In PJM, if the monitor sees things like that they start with an informal discussion with participants. After that they have no authority, they simply refer it to FERC. There are fairly significant resources required to monitor effectively. This includes economists, engineers, IT types, access to data, and storage organization of data analysis.

The details are critical to proper monitoring. For instance, the way in which operating parameters can be modified in order to change the uplift payments that units receive. The same for a merger analysis, loop flow analysis, or detailed analysis of congestion. All require an enormously detailed understanding of the system.

Power markets are monitored because they used to be regulated, not because there's something unique about electricity market. It's also because FERC has regulatory requirements for just and reasonable rates. The general mandate from FERC for monitors is not yet clear enough. The mandate must be from the FERC and not the RTO. Reporting and filing authority is not clear enough. There needs to be clear authority to make referrals to the commission. Market monitoring performance has been incomplete. They have a limited but positive impact on the market. There is a clear role for monitors in the future but there needs to be a better definition of what that role is.

Question: To be clear, monitors should be able to go directly to FERC without clearance from the RTO?

Speaker 1: Sure. Market monitors work for the RTOs and are subject to their HR department. They get promoted, paid, given bonuses, and office space all by the RTO. It's a real set of constraints on a monitor's behavior. Is that appropriately clear?

Speaker 2.

FERC defines the market monitor job. Primarily it is identifying potential anticompetitive behavior by market participants and adding more analysis. FERC wants the market monitoring unit to properly interpret existing market rules. Second, they should suggest improvements in the market rules based on their analysis. Thus, the annual review and report on the performance of the wholesale markets is vital. The value of the market monitoring unit comes from information and knowledge accumulation, the analysis of market improvements through rule changes, and through mitigation of anticompetitive behavior.

The need for monitoring is fundamental because electricity is not storable and there's too little real time demand response. It's an imperfect market. There are problems in the environmental area, a contrived transmission market, and reliability as a public good. Before reliability can be privatized there are fundamental questions about the obligation to serve. This creates fundamental incentive problems; unilateral market power cannot be avoided. Finally, we know price caps are a necessity, not an option.

There has been a significant shift in common wisdom about what electricity restructuring is. We now understand it is a process, not an event. To make the process more robust and stable, market monitoring provides a necessary feedback loop to improve market performance. Clearly, the focus for the market monitor should not be narrowly focused on any specific aspect. It's broadly construed as market performance including efficient prices, reliability and efficient investment.

In ISO New England there are two market monitors, like California, and probably not much like PJM. The internal market monitor reports to the ISO. Their authority is specifically defined as the mitigation of real time market manipulation or market power abuses. Generally their market design is ex ante. As soon as market prices are set they will not be recalculated even if there is an abuse detected. The mitigation will focus on the correction in ex ante for the future.

In ISO New England the general approach is a conduct and impact threshold. The conduct threshold focuses on whether individuals' bidding behavior deviates from the reference price level. The impact threshold is a measurement of how the deviation affects the market outcome. Their market monitoring unit has real time on call rotation. Whenever situations arise, actions are taken almost immediately.

ISO New England uses a reference price calculation that is quite different than PJM. The conduct/impact threshold approach relies on the reference price as a guide to just and reasonable prices. There's also a set of market behavior rules called appendix B that gives the market monitor some discretion to make recommendations to the FERC.

A market monitor's power comes from its access to information, its ability to assess market performance, and to report to FERC. If it can facilitate open communication with market participants it can function fairly effectively. Most participants want to be cooperative citizens. Sometimes they may not fully understand certain aspects of market rules. Very often some minimal communication can lead to immediate attention by senior management within companies and they can correct things internally. This communication process involves regular weekly communications with FERC. Participants are aware of this process so the information flow is efficient. This encourages efficient behavior in the market place.

The internal market monitor also serves the board and senior management to insure the market is best served. This empowers the market monitor if there are actions that the board or management can take via the management route to prevent undesirable behaviors. These may be perceived narrowly as something that only affects reliability, not market performance.

Cold snaps in the winter are a constant problem in ISO New England. There is a high and increasing dependence on natural gas, despite the fact that the region is located at the end of the gas pipelines. There are competing uses of natural gas, for heating and generating electricity. With the price cap, generators may find it more profitable to sell natural gas to the heating market. From a market monitor's viewpoint this is a form of economic outage. The ISO has to find the most efficient way to allocate resources.

Another winter issue is related to two-fill units. If a unit can burn both oil and gas, they switch the orders when the fuel prices are very volatile. When oil is more expensive, the unit can have their choice of fuel. They can take the unit out of gas and benefit the regional portfolio. From a reliability standpoint it's better for the ISO if the unit can access the lower cost gas and use oil as a backup instead. The oil can be stored on site. This is a reliability issue that affects the interaction between the gas market and electricity markets. However, there can be profit motive behind all these different strategies.

The ISO introduced a new ancillary services market last year. The initial intention was to handle limitations on the so-called the mileage payment. The mileage payment is a measurement of how much a unit has been used to serve regulation. It was thought to be a fairly straightforward change initially. However, in October the cost of regulation doubled from $4.5 million to $9 million, and in November it went to $11 and to $18 million in December. The market monitor checked around and saw it was occurring in PJM and New York. That's not the end of the story however. Some financially stressed companies pulled units and shifted the supply curve in the market place. There's a lot of learning going on in the market.

The immediate question was whether these were bad guys or was the new market design badly implemented and in need of a fix. There was tremendous pressure from the states and from management. In a case like this, it's important not to jump to conclusions. As it turns out no signal factor could explain all of this; even with the bad timing of natural gas prices rising. As analysis continued, and talks with market participants began, the costs began to drop.

The costs have gone down considerably. The market doesn't work as theory predicts. The regulation market is a small market, it's about 1% of the whole energy market. Participants haven't figured out their bidding behavior yet. Some got a windfall out of this market rule change. Further, there are also entries and exits in the market. It takes time to discipline the market. So in a way the market works through entry and exit. In general this did not look like manipulation of the marketplace.

A big issue now is the new capacity market. There has been a lot of discussion on the settlement process in New England. The settlement process involves agreement consensus on design principles and risk sharing. The risk sharing is somewhat controversial and still ongoing. The market monitor will be an important element in this new market design. Market power in the capacity market will require much more discussion. Currently, these rules are only just starting to set the general principles.

A final issue is FERC's new market manipulation rule. This adopts an SEC approach towards discipline for fraud and deceit behavior. FERC has more remedies for abusive behavior in the new Energy Act. Their cop function is likely to be shifted more to the court, through a litigation process. The one concern is that the SEC precedent has not been able to address the issue of one party manipulative behavior. We'll see what they come up with.

The market monitor needs to focus on the big picture, the overall performance of the market. Their authority is very specific, and provides an important base to insure the function of real time markets. Data analysis, knowledge and open communication are their most powerful tools. Their partnership with FERC, and state regulators, is essential.

Speaker 3.

I'm going to do a quick review and lessons learned for FERC's OMOI [Office of Market Oversight and Investigation] for both policing and watching markets. Just and reasonable rates through competition require adequate infrastructure, effective rules, and good enforcement and oversight.

After the California debacle, OMOI got to pick from a pool of about 180 volunteers within FERC, and took about 60 of them. They also went outside for investigative, trading, and finance experience. They split the department into oversight, investigation, and communications functions. Early on, investigations equaled the other two pieces. That's not true today, oversight has shrunk. Generally, it was a very professional staff with many advanced degrees. The department was very team oriented; a big culture change at the commission.

It's true that the vast majority of market participants are trying to do this straight. They're looking for a competitive edge but trying to do it within the rules. Often, they'd like to understand what the rules are. OMOI used a hot line which worked reasonably well for whistleblower type reports. It was less successful for people seeking guidance.

They had a good relationship with chief risk officers. One of the goals for the office was to be proactive and head crises off before they happened. When price reporting was about to end, they worked out a voluntary private sector solution with the chief risk officers. A big concern in '05 concerned FERC's attempts to be more rigorous without providing enough guidance for companies to understand what they should be doing. There were two elements to that. One was simply that rules were not crystal clear. Second, federal investigations are required to stay confidential. When the settlement is made public, the big problems are not and people look like they were nailed for doing nothing.

There has been a good relationship between CFTC and FERC that had been disastrous previously. This was helpful. The market monitors are absolutely essential but it's been a confused relationship, and there's no signs of that changing in the foreseeable future. For instance, market monitors were originally supposed to be an extension of the commission's staff. Then legal folks noted that kind of structure was illegal.

They also wanted to help empower RTO boards more. There was a famous meeting with the RTO boards. They were working on a mechanism to get more information to other board members that would report on general issues. However, commission changes didn't allow this to get fully implemented.

Much of their work was simply showing participants the kinds of things they were seeing. They began regular seasonal assessments, that was big progress. This became a strong process for helping the market stay aware of issues.

Knowledge is critical and it can't just be knowledge for the monitors. It needs to go to the regulators. A lot of information transferred to the commissioners through very long, closed meetings. Though there is extensive variation among commissioners in terms of their interest in this. Getting the information to state commissioners is also important. The FERC reports were put out with the sensitive stuff missing, and it's become popular with a number of state PUCs. It's called the market snapshot.

With the MMUs [market monitoring units] and other regional players, I don't know how that will play out. Each market monitoring unit is different. There is no replication. Not one ISO or RTO has the same broad structure for their market monitoring unit as another.

Broad support from FERC has been essential. There was a moment when the MOI could have been reorganized and lost its effectiveness. Much of that effectiveness comes from the analytics and the enforcement people working together on the same teams. This provided guidance and effectiveness for enforcement, and it provided pullback on the bridle on occasion too. Market monitoring is tough. It's tougher than cost of service regulation. The markets have geographic differences, regulatory differences in the hybrid structure. There are seams issues, and you've got jurisdictional issues too. There's many complexities.

There's real tension between gaining commission support and independence. This is true at the federal level and at the market monitor level for RTOs. If you're going to be part of your organization, people want you to be on the same page that they're on. If you're independent and make objective assessments, this can conflict with organizational preferences, and that creates tensions. There's a need for support at the top to help the monitors and the enforcement side stay independent.

The relationships with market monitors are helped by common metrics, so that each market monitor is reporting on their market performance the same way. However, MOI couldn't get past the half dozen metrics that they thought were important, and which had the right level of agreed-upon precision.

Another challenge is the talent drain. The team in the last 3-4 years came after the Enron mess, not long after 9/11, when people responded to a request for public service. Virtually no one said, "I'm just having too good a year." The idea was give FERC at least two years, get a program in place, train someone behind you, and create a capability that the country needs. Now the marketplace is looking good again, the esprit de corps is not the same. It's hard to get strong talented people.

It's incredibly important that MOI is proactive; it takes constant and continual improvement. Currently, MOI needs to get monitors integrated into FERC processes. Congressional and state pressure has been constructive and helpful for maintaining the information flow from FERC to the states and helping organizationally at the commission.

The industry needs to exert leadership on the integrity point. Market integrity helps everyone. It can be done with industry leadership and it's better for industry to take the lead. With the new legislation the stakes are very high and threatening to companies. Many are trying to step up to it. They may be able to work with FERC to get through the confusion. Recently, MOI put out a new compliance handbook. That's some real progress for that office in terms of outreach and understanding. There is a wave of self-reporting going on right now, so many players are clearing the decks to move forward.

Speaker 4.

The number one role of the market monitor is to address unilateral market power. As a general outline, I'll discuss why electricity is different and talk about the specific responsibilities of the market monitor. Monitoring is smart sunshine regulation; shining the light intelligently to allow authorities and actors to take appropriate actions. Finally, I'll emphasize rule compliance, address harmful behavior, and look at system reliability and market efficiency. I'll deal with California in some detail. The emphasis here is on eliminating improper behavior and using punishment only as a last resort.

If someone were going to design a product that would be difficult for a competitive market they would choose a product with all the characteristics of electricity. Further, you can never get rid of regulatory oversight because the transmission and distribution networks are a monopoly provided service; it makes the process even more complicated.

An additional complication that feeds into the competitiveness of the market is the local market power problem. Electricity needs to be delivered through a potentially congested transmission network that wasn't built for a competitive regime with multiple suppliers. It was built for a vertically integrated regime.
This provides opportunities for suppliers to take advantage of their favorable location in the network and raise their prices. Demand for electricity in many cases confronts suppliers with a completely inelastic demand curve, even if it reflected real time prices there's almost no

limit to the price they can bid. A mechanism is necessary to effectively mitigate or deal with those circumstances.

These mechanisms existed in the power pools of the East Coast that became the ISOs. They already had local market power mitigation mechanisms. California never had a power pool regime, and did not have an ex ante local market power mitigation mechanism until 2001. Before that it was pay as bid. They know they need market power mitigation but the optimal form is elusive. It will change as the market design does. A major role for the market design process is to refine the local market power mitigation mechanism. It is the kluge that we'll need, especially with a reluctance to build transmission capacity.

Since little problems easily develop into big problems, a key role for the market monitor is to help people learn. Often there are things the market monitor can provide, like useful unbiased information analysis of proposed rule changes. It's like a Consumer Reports view of market design changes and market outcomes.

The market monitor can play a major role in transmission expansion. Transmission externalities were internalized because the vertically integrated firm was told to supply power to customers at regulated price. They decided the best way to do it, a combination of generation and transmission. In the wholesale market regime, transmission and generation are separate. We've lost that economy of scope between transmission and generation. The transmission network is a facilitator of a competitive market. Its configuration impacts the extent of market power that suppliers can exercise. If everybody can compete, it limits local market power and price leveraging to the wider market at large.

There are two imperfect worlds. Under the imperfect world of regulation, there was an optimal transmission network for it. Under the imperfectly competitive wholesale market regime, there is an optimal transmission network for that. The market monitoring process can provide input into the design of the transmission network to facilitate competition. California uses a team methodology to take into account a wide variety of factors to decide on transmission upgrades. The market surveillance committee has a role in that process.

Market monitoring means preventing harm to consumers, not preventing high prices. Firms should be able to maximize profits. A perfect regulatory process is impossible. If we could, then we should abandon all markets, because perfect regulation would yield lower prices for consumers. However, perfect markets don't exist either. This process requires an optimal combination of regulatory intervention and market processes. Market monitors should purge "market power abuse" and "market manipulation" from their vocabulary. It gets people upset and there's proper definition of it. The real issue is preventing substantial harm rather than finding manipulators.

The first step is public release of data. Anything the ISO uses to operate the market should be available to market participants for analysis. Similar to financial markets. The only confidential things are those that don't affect the physical operation of the network such as financial contract positions and other similar items. They would be useful to the monitoring process, but need to remain private.

FERC's data confidentiality policies were a problem in the California crisis; they couldn't release information, so the major benefits of sunshine regulation couldn't occur. It limited one of the goals of the market monitoring process: smart, good analysis. The other problem was the political process, journalism and public policy in the court of public opinion.

They need to produce the consistent qualitative measures of market performance, like vital signs of a market. They need a clear idea of their meaning so they can understand that prices are high because input fuel prices are high, not because suppliers are exercising market power. They need to be aware of operating constraint affecting participant behavior.

To prevent harm the right incentives have to be in play. particularly for system reliability and market efficiency. Priorities are important too. Four thousand hours of price at one dollar too high is more harmful to consumers than two hours of prices that are a thousand dollars too high. Those big high but rare prices also have some potential benefits. The four thousand hours of slightly inflated prices have large costs and provide very few incentives to fix them.

Electricity differs from financial markets. The integrity of transactions is important for both worlds. Penalties and sanctions to insure compliance with market rules and within agreements. In electricity there is a common grid, different from a financial market. When Enron went bankrupt in the financial markets there wasn't a hiccup in the wholesale markets, but their operations in the electricity markets affected everyone and everything.

The common network means that if someone is doing something that is profitable for them but is reducing the reliability of the network, it affects everyone. The monitor has to deal with that. It degrades other's ability to earn money. The grid has to be operated in the best interests of all market participants.

Working in electricity markets can make you humble. There's a lot of things that are unintended consequences; some more predictable than others. When these things happen, the ability to prevent massive wealth transfers that are difficult to undo is critical. Economic game theory defines all possible contingencies when solving for an equilibrium in a game and people don't go to unpleasant contingencies. If you don't clarify all contingencies, then some players will test you. That's a large part of what happens in these markets when bad things happen.

It's important that rules are easy to factually verify. If not, it should be off the books. Market manipulation rules that are nebulous don't provide benefit. A clear process should be in place to deal with problem behavior. A key problem for monitors is to establish that actions are consciously intended to harm the market. Sometimes it is unintended, so a process is needed to make that finding. First, identify problem behavior; then give opportunities for market participants to solve them; next, collect information to potentially penalize a participant for this behavior as a last resort. Mostly, it's the process of putting out information and allowing the market, political, and regulatory process to solve it. Even if a penalty conclusion is a last resort, it needs to be a well-defined process known to both the market participant and the regulator. This helps preempt having to go to that conclusion.

Risk management and electricity retailing are an issue. This is really spot price mismanagement. They are assigning fixed price obligations to sell to retail customers, and then hedging that risk with a generator to ensure the retailer is not exposed to substantial risk. This is an outstanding aspect of all market monitoring processes in all markets. It is still being addressed; it's at the heart of the resource adequacy debate. Defining a prudent hedge of spot price risk is the key to resource adequacy.

The market monitor has to focus on questions of market success, not on finding and punishing bad behavior. Improper massive wealth transfers can occur without bad behavior. They must collect and display the data; perform analysis and make clear that problem actions have to stop if they are degrading system reliability. Finally, they can help fix the market rules that may be causing problem behavior in the first place.

Question: What will happen when California and the West have a $400 price cap and the rest of the markets are at $1,000 or more. Even though they're not physically interconnected, what are the implications as the markets interplay with each other in gas or electricity.

Speaker 4: It's unrealistic to think the market will ever have totally self-regulating capacity markets or demand curves for operating reserves as a way of managing scarcity pricing. An offer cap is just one more piece of that. It may be a relatively blunt tool. There's no magic to any particular number. A cap better not be below the cost of a gas fired unit with a peak rate in actual gas costs. As long as it's above that and net revenues can sustain the market, than a range of choice in the offer cap is reasonable.

Comment: Generally, a price cap limits incentives for investment. The question is what are the immediate implications. Generally, a low price cap will discourage a peaker unit more, and the base low units may not be affected as much. It can influence the mix. It also discourages the demand side. However, other measures can be taken to balance it. In the long term market performance depends on demand side participation, you pay a premium on that. If the demand side kicks in, the need for the price cap will diminish.

Comment: The only positive effect of a price cap that low is political, and that is only a short run benefit.

Speaker 4: If the variable costs of the highest cost unit needed to meet load is below that bid cap, you can run a market. If you have it, you need to plan ahead. In the old days of regulated airfare, if I didn't want to get stuck with a $2500 airfare at the last minute, I'd have to plan ahead.

You can run it on a lower bid cap if it doesn't preclude any generator from covering their variable costs. However, buyers better have contracted in advance for most or all of their supply far in advance of delivery. The real time could be particularly painful. With that caveat in mind, you can run it.

Comment: Texas is going to raise the offer cap, synonymous to price cap, to $3000 by 2009 and then have no restrictions on anybody's bidding. You can bid anything you want.

This provides enough incentives for people to enter in and bid into the marketplace. However, it's not the offer caps per se that are the problem. In principle, offer caps are quite consistent with the competitive market, as long as you satisfy the conditions just discussed [contracting ahead in the market].

The real problem is the interaction of offer caps and other rules in the market. These get very difficult. For instance, if the operator invokes an RMR [reliability must run] contract. The tight situation is avoided, and the price goes down. However, the price should be going up, to reflect the scarcity. Offer caps are going to be in the Northeast for a long time, but it's not a problem if we fix these other features. Can we fix the other features? Otherwise, market power mitigation through offer caps is always going to end up in depressed prices.

Speaker 1: There's no evidence in PJM that the thousand dollar offer cap has had any significant impact on prices whatsoever. It might have had an impact in ten hours or over the last six years. The second part of your question is critical. Revenues in the energy market interact with revenues from other markets. The acid test of a market is whether enough revenue is being produced to provide incentives to make new investment. If the market can't reproduce itself, it's not a market.

Neither PJM or the others have passed this acid test. PJM is implementing scarcity pricing. Limiting the highest price to the highest incremental cost of the highest cost unit on the system is fine when you have lots of supply. It's not appropriate when you're out of supply. PJM is explicitly recognizing that now.

Between capacity markets and energy markets, you need to be able to assure a reliable system and enough revenues to be reproducible. It's some combination of energy market pricing with offer caps, with either a capacity market, scarcity pricing, or some application of operating reserve demand curves. It has to result in enough revenues to incent new investment.

Speaker 2: One has to be very cautious about an incremental solution. Adding an arbitrary price cap without a fundamental basis can lead to yet another. The price cap should be derived from a fundamental idea or concept.

Interaction between markets is also an issue. The regulation market is small, but the tail can wag the dog. Through market interactions, issues in the regulation market can be a reflection of problems in others.

Speaker 3: There are idiosyncratic and difficult problems in each market. The monitoring function is going to remain very challenging. Every time they get their hands on one piece of it, it pops up somewhere else.

Speaker 4: If there was effective local power mitigation mechanisms, the bid caps should be very high. The market is not completely constrained, most suppliers can deliver their power to any location in the network. For markets the size of PJM or California, how can anybody really significantly influence the price. If there really is a system-wide scarcity of energy, then we should be pricing to get demand to go away. This is only possible if local market power mitigation is addressed.

A difficulty is that many of the local power mitigation mechanisms have leveraging properties where suppliers can take something they have locally and leverage it to a larger geographic area. When these large markets are unconstrained on a system-wide basis, and the local issues are addressed, it is a very competitive market.

Comment: Some speakers have said that removal of caps is not an option. I'm referring to spot market caps, primarily, but all caps ultimately. First, why is it not an option? Second, do you mean now and in the near future, or forever?

Speaker 2: There are two premises for that assertion. Electricity is not storable, and demand response in real time is not there. This means that price caps are inevitable. If you remove them, the price could be infinity. The market design cannot be built on that possibility.

To remove this constraint? It does not take a lot of demand response to remove that requirement. A technological change could address this, we all wait for a better battery.

Speaker 1: The caps in PJM and similar markets are only relevant during periods of relative scarcity. On a day to day level they are not relevant. The energy market is always long because of the capacity market, which results in more competition and tends to result in lower prices. The issue becomes, how do you deal with scarcity. It's seldom going to be in the entire RTO region. PJM's scarcity pricing rules let the price get higher, still constrained by the cap, when there is a scarcity condition.

Making sure that the demand and the price look right during times of relative scarcity is what all of these issues are about. Capacity market issues, an operating reserve demand curve, scarcity pricing, and the disagreement about offer caps all revolve around this.

Speaker 4: In the eventuality of an infinite spot price buyers would be willing to be curtailed at a determined price; lots of capital equipment would be in place. The old regime was constant expectation of supply. If the institution had developed differently, consumers would have figured out ways to go away when prices got too high.

Changing this paradigm, even if you change people's minds is hard. A whole lot of infrastructure needs to be there to allow for this kind of response. Only if everybody has a meter, knows their consumption, can see the price will it happen. Right now some consumers are getting a subsidy. They're not keen about getting rid of that subsidy. It's very hard for the CPUC to say the default price they pay is the default price you pay for every other good you buy, which is what the market is willing to sell it to you at, not some average price that we set.

The Australian market has effectively a $10,000 bid cap. If anything, they're thinking of raising it because of concerns with generation adequacy. The UK doesn't have an explicit bid cap on their balancing mechanism, and prices are really volatile. This causes people to want to plan ahead, as we discussed.

Question: PJM has a new market litigation proposal for operating parameters. For example, a peaker with a minimum run time of two hours changes their minimum run time to 24 hours. They know PJM will commit them because they are in a critical area, even if they are only needed for 3-4 hours. It's becoming a pay as bid strategy. This is a kind of market power. Does PJM see this as market power? Are the generators getting away with a pay as bid paradigm?

Speaker 1: I'm not sure it's pay as bid. It is market power. Let's assume say someone has a combined cycle in the system, and they're needed for operating reserves. The operators need them on and spinning everyday, available to provide energy. The company quickly figures this out. Instead of the unit having a three hour minimum run time, they make it 24 hours. This is an unintended consequence of the three part bid rules; startup, no load, and marginal cost. The only piece that fits LMP is marginal cost. PJM markets will make you whole for startup and no load if LMP revenues fall below the sum of all of those revenues.

The unit is not economic for most of its hours. It's not required for most of its hours, but it can force other market participants to pay a significant chunk of money to it to operate 24 hours. It doesn't matter what you call it: market power or manipulation of the rules. It is, right now, consistent with the rules. PJM is trying to modify the rules to insure that they don't pay units based on an artificially long minimum run time.

The operator decisions have big impacts for the market. The operators are selecting a resource. Second, the operator is making an optimal decision. What PJM is proposing to do in the operating parameter limitations is the first step to a more rigorous market based solution to it.

Comment: You're not seeing it as a pay as bid. It is pay as bid, the generators ultimately get paid what they offer to the market for the supply payment. They're not really clearing the market, they're not really setting LMP. They get made whole based on bogus parameters.

Speaker 4: Economists have pointed out that pay as bid and a marginal costs offering will result in pretty much the same outcome if conditions are right. I think some participants have tried to characterize it as pay as bid as a way of making it sound as if it's rational and market based, when in fact it's not. It's a form of exercising local market power.

Question: Australia's releasing of bid data the same day was discussed earlier. A concern for this is that it could enable the exercise of market power because people could play signaling games on a daily basis with those bids. Is this an issue?

Second, I'd like to commit a bit of heresy and suggest that reliability is not a public good. It is a private good; once we use up the reserves, they're gone. Operators have to start curtailing load, or reduce voltages at the distribution level. It's excludable. They can shut off breakers, people can install backup generation, some choose to become interruptible load. I'd appreciate your comments on this issue.

Speaker 4: Thank you for clarifying that reserves are not a public good. I completely agree with you. A public good means I consume and someone else gets just as much. That's not true with reliability.

It's hard to find any evidence of signaling games in any market. Certainly, information on forward contracting position should not be released. If you have private information on your forward contract position, any pattern of bids can be rationalized as unilateral profit maximizing for a given set of forward contract positions, or forward financial positions that you might have. Even though you're selling a lot of energy, you may have an incentive to drive the price down low, even though you're selling very little energy, or you could have the incentive to drive the price up a whole lot depending upon what your forward position is.

Signaling games aren't relevant because big competition should come in the forward market first. If signaling games were to take place, then people can see it because the information is available and easier to detect.

Speaker 3: I'll speak on the data release point. I'm in favor of releasing more information rather than less. However sometimes the data is very messy and has to get fed back to the submitters.

I don't know who would manage the process in real time; I don't know how you'd make it happen. Storage data challenges for EIA have been immense. Yet, that's simple compared to bid data, it may not be practical. You could put it out without quality control or review but there are problems with that.

Speaker 2: In theory there's no problem with releasing bid data but the practical considerations are difficult. How market monitors may receive the information or inquiries from the market would be hard to handle.

There is one aspect of reliability that is not well understood. It's the security, the probability of blackout. That's different from a rotation blackout. If there is a way to exclude some customers from a blackout, that is not a public good issue. The public good issue is if a unit breaks down in the system, there is a probability the whole system will go. That affects everyone at the same time.

Speaker 3: Let me disagree with everyone. There is real signaling. FERC's OMI has seen it and been told about it from generators.

There are a couple dimensions with data release. Frequency is part of it, but there are more important issues. Frequency could trade with the signaling issue if everyone's a deputized market monitor. that's a very real consideration.

The granularity and type of the data is important. For instance, PJM posts offer curves that folks get frustrated looking at because they don't have parameters to interpret them. They don't have min run times, startup or load costs. Increased detail should be included and the release time shortened to three months.

Finally, it's eminently practical to do it. We could post it every hour, we could post it every day, we have the data in the system. It's no big deal to put it on the web. The question is should it be done?

Outage data should be posted too. Outage data has historically been jealously guarded by generators. However, there are now services that put surveillance technology under transmission lines near generating stations, and they interview the guys who work at the units.. They pay people to observe the units. There are lots of ways to get that data. It has a huge impact on the market and it should be available close to real time.

Comment: Data is available off the Spain website, the Colombian market website, as well as the Australian, the NEMCO website.

Speaker 1: One has to be careful characterizing the Australian $10,000 offer price. It's limited to a certain number of hours at which point it goes back to $100. It's also a different market structure.

Question: The most powerful market monitors are competitors, because if they see an opportunity to make money they will do it. They will exploit opportunities if there's mispricing in the market. One speaker said the role of the market monitor is to facilitate the creation of competitive markets. That's in tension with another role which is to insure that prices are consistent with short run marginal cost as the market monitor perceives it. This includes reference pricing. Clearly there's a middle ground.

Short run market power is a concern, but are those signals to the market to respond? How do we tread this delicate balance between allowing a certain amount of market power – not all market power is bad, some of it the market can handle – and pursuing and eliminating other kinds of market power ?

Speaker 1: It's not anyone's goal to eliminate all market power. The markets would certainly be competitive if everyone offered the short run incremental cost, and it cleared that in every hour at every bus. That won't happen. Good rules, good incentives you get as close to that as feasible with the exception of local market power. The better you make the rules the more likely it is you are to have a competitive outcome without having to worry about detailed intervention.

Speaker 2: That's a good question. There are two issues: market power and marginal cost pricing. The market monitor's role is to implement the market rules and make sure they are being observed. Built into the market rules there is some flexibility, bidders can overbid their marginal cost if they choose to without being disciplined. The question is whether those rules are adequate to provide enough room for certain market power to be reflected in the prices. An assessment of this can be done by looking at the overall market performance. One problem is that the market monitor is limited in their discretion.

Speaker 4: I would love to eliminate all market power from the market, but economists know there's no free lunch. Intervention and mitigation are costly and market power is costly, so it's a case of picking your poison. Temporary high prices punish the supplier that undersupplied relative to his contract if everyone is hedged. This benefits the supplier that comes in to provide that power when it is needed. This provides a the signal for the market to solve the problem.

The market monitor is a facilitator to help solve these problems. Data release, sunshine regulation help participants understand how the market is really working. It allows them to respond, and to avoid regulatory intervention, which is costly and has a lot of time lags.

Speaker 3: Yes, better rules lead to less intervention, and our antitrust system is an effective competitive mechanism. Market monitors don't think they are exercising discretion but market participants think they are discretionary decisions. An issue for monitors facilitating resolution of problems is that this ignores input from the overall framework and FERC jurisdiction. It's a sticky question between ISO/RTO and federal level jurisdiction. FERC will need to be more agile in its decision making.

Question: There are annual reports from the market monitoring organizations indicating that revenues are inadequate to support entry into the market place. Other reports indicate that we have near term resource adequacy issues. Doesn't this indicate market monitoring mitigation overkill? Are focusing on low prices rather than economically efficient prices?

Speaker 1: Monitors wish they had that much impact on the market. There's a huge gap between your premise and conclusion. Generally, the markets over the last six years have not provided enough net revenue to cover the new costs of a CT, a combined cycle, or a coal unit. It's not true for a coal unit any longer. There are also locational capacity issues.

None of those issues are the result of excessive mitigation. They're not the result of offer prices. They're the result of bad market rules. One, we don't have a locational capacity market. The aggregate market is very long but specific regions are certainly very tight, if not scarce. Market rules create the problem, not mitigation. The overall offer cap in PJM has not had any notable effect on the revenues of generators or aggregate prices.

Speaker: It's important to make the distinction between local reliability problems versus a system-wide problem. There's plenty of generation system wide. We need investment locationally. There should be years when the average price in the market is not sufficient to sustain the cost of a new unit because you don't need any more units on a system-wide basis. The correct locations are the problem.

Question: The speaker just alluded to the structural problems. This should be an even bigger role for the market monitor because they send bad signals day in and day out. They have at least as big of an impact on the investment and the overall good of the market as bad actors do. A stage two emergency last summer had prices under $200. Those are bad signals and the market monitors should investigate. Why are prices clearing too low?

My question addresses market power and locations and the price signal to draw capacity investment to those areas. How is a fair price set so that consumers see the right signal for investment in transmission upgrades? If you control for market power, what's the right price?

Speaker 1: I wish I knew the answer to that question. First though, market monitors are addressing those broader structural issues. They were a key part of the scarcity pricing implementation in PJM, which came because of the low prices last summer. PJM is attempting to address the locational issue through the locational capacity market. Clearly, a real incentive consistent with the costs of new entry is needed. They are attempting that via RPM but there are other ways to do it.

Question: Is the price of new entry the right price to control for market power in those areas?

Speaker 1: The offer cap in the energy market should be based on the cost of entry. The price that markets should pay new capacity is equivalent to the cost of new entry not revenues.

Question: If you're addressing the structural issue through a cap type mechanism, or a local capacity, is that the right price to use as a benchmark?

Speaker 1: If the market's short and you need capacity, that is the right signal.

Speaker 4: The beauty of an LMP market means that energy prices at those locations should reflect the price to supply energy at those locations. The complicated part is determining what is too much market power locally, and what mitigation mechanism will be used. Further, if the generation isn't there to serve the load at that location, what will happen next? These decisions should motivate LSEs to make advance arrangements that insure shortfalls don't occur. Then, the market decides the appropriate mix of generation to serve that energy. The new entrant will get the LMP at that location, and that LMP will reflect the local market power mitigation mechanism that's in place.

Clarifying the details of a local market power mitigation mechanism so that new entrants the landscape is critical. Providing incentives for the load side of the market to purchase that power enough in advance to solve the problem is also vital.

Speaker 2: One thought. In theory market monitors are expected to help the market make the right choices to get the prices right, but in reality they are just expected to get the right prices.

Question: Is OMI considered an agency that follows the policies that FERC sets? Thus they are a policy arm of FERC. Or should they be independent of FERC and its policies?

Speaker 3: It needs to be an integral part of FERC. The tensions come up more on the investigative and enforcement side when due process issues are necessary. At those times politics can rear its ugly head and they have to fight it.

Question: We're struggling to come up with a good role model for market monitoring. FERC is looking at the SEC model, but the SEC model depends on self-regulating organizations and it has a tremendous amount of power to get a lot of personal records. The market monitor doesn't have that. Second, the SEC doesn't have to be concerned about unilateral exercise of market power. Is the SEC model the right one?

Speaker 3: There are some insights and best practices that are probably transferable but it needs to be a federal energy regulatory scheme, and it's going to be very different. The rationale of the SEC is about protecting individual investors. There are practices that they've developed that make a lot of sense. These can be used without using the whole model.