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RAPPORTEUR'S SUMMARY*

Session One.
In Search of Perfect Prices: Incremental Improvements with High Leverage

The California experience with exceptional dispatches raises questions and is an example of how reliability based commitment and related dispatch decisions do and should affect energy prices. Similar concerns arise in the eastern interconnect over the size and allocation of the uplift payments like the revenue sufficiency guarantee in MISO. The rise of the smart grid, the challenges of integrating intermittent generation technologies, the hoped for great expansion of demand participation, transmission expansion, and the continuing role of forward generation capacity markets, all present major policy concerns that hinge in part on the perfection of energy prices.

While the perfect can be the enemy of the good, there are opportunities to improve on the imperfect prices used today. Previous sessions have addressed a number of theoretical ideas that have been the subject of active investigation and testing. What is the state of inquiry into alternative pricing designs? What have been the results of realistic scale testing in MISO of the pricing design that integrates unit commitment and minimizes the resulting uplift? How can better scarcity pricing be implemented to provide better signals to the users of the smart grid? What are the implementation challenges and timelines?

* HEPG sessions are off the record. The Rapporteur's Summary captures the ideas of the session without identifying the discussants.

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Speaker 1.

The Midwest ISO has been investigating new mechanisms to set prices in the markets for a while. They've made some good progress. I'll discuss what they've done, and where they are today. Some of the outcomes from the markets raised some questions that required a new approach. For example, there were questions of the uplifts they were charging. Could they modify the prices so that the uplifts would be lower? Was there a different pricing structure which would cause uplifts to be reduced? There was emergency demand response being called early in the market and the demand came off in chunks. The price would drop in real time. A variety of situations created a need for a reassessment.

MISO, similar to most of the RTOs, has a day ahead market cleared using security constrained unit commitment and economic dispatch software, to minimize the cost of the supplies they're procuring, less the value of the demand they're serving. That's followed by a reliability commitment process, using security constrained unit commitment to make sure there is enough capacity in real time. They dispatch committed resources in real time using security constrained economic dispatch.

Locational prices, in day ahead and real time, are set each day using security constrained economic dispatch software. This determines the price at the margin, the price at a location is equal to the marginal cost of serving demand at that location, as measured by the economic dispatch algorithm. They solve the dual of the SCED. This is typical for all the RTOs.

This approach comes from microeconomics and game theory. If one assumes a fixed commitment, one can show these prices are market-clearing prices for the committed units that maximize profit. Similarly, they're efficient prices. These are prices in which people are willing to produce and consume at levels which support the schedule and maximizes societal surplus.

Game theory shows that these prices can be used to allocate the societal surplus that's been produced. No one has an incentive to leave the pool, commitment and dispatch, to schedule, on their own. They can't do better than what what's been allocated to them.

When commitment is added to the mix, all that changes. With commitment in, there usually aren't market clearing prices. One cannot find a set of prices which would incentivize the profit maximizing generators end loads to produce and consume at the scheduled quantities. You show them a price, and they'd either want to produce or consume more or less than you want them to produce. This happens because the pricing method doesn't include startup and load costs. Since it doesn't do that, the RTOs have to pay people uplifts, to get them to follow the schedules.

Similarly, game theory shows that the prices don't allocate societal surplus in a way that eliminates incentives for people to leave the pool. Some people could do better by leaving the pool and scheduling on their own. The fundamentals change when you put commitment in the mix.

MISO, along with the LECG consulting group, have been looking at Convex Hull Pricing. It's a complex name. Rather than using a Security Constrained Economic Commitment model to set the prices, it uses the dual of the security constrained unit commitment problem to change the prices. It allows commitment decisions to have some effect on the prices. SCED [security constrained economic dispatch] can't do that, SCUC [security constrained unit commitment] can.

The prices produced by this method minimize the uplifts needed to pay generators and loads to follow the schedule MISO is giving them. It also ensures the amount MISO has to pay to ensure that they're indifferent to following the schedule is minimized. They incorporate startup and no load costs in the prices which SCED can't do. They also minimize incentives for parties to leave the pool, commitment and dispatch. In essence, it minimizes the amount that anyone could increase their allocation if they left the pool. These are very good reasons to use Convex Hull Prices.

The next big question for MISO is whether they can actually solve these things, in practice? Can they compute these prices and solve the dual of the SCUC problem? What do the prices look like, in practice, when they solve it? They've been working on this over the last couple of years and coming up with test bed software.

The total generation cost they want to minimize includes startup, no load, everything rolled in, minus the load they're serving. It's subject to several constraints. The first is the system-wide power balance constraint. The sum of the generation, E, is a vector of one. They sum all the scheduled generation, minus total scheduled load, minus the losses caused by that generation and load. This has to be equal to the offset, and they linearize the losses. This is a linear power balance equation. They've also linearized all the transmission constraints. The really complicated stuff, they lumped into constraints on individual generators. Ramp rates, startup, no load, min run, all that, is just a complexity which is buried for each specific generator.

Then they formed the dual for this problem, and here's where it gets hard. They multiply the power balance constraint by a price vector of the lambdas of the power balance multipliers, and multiply all the transmission constraints by a pricing vector. They bring those into the objective function that needs to be maximized. It's very complicated, because there is a mess of minimization problems, for every generator, and each load.

It's also a difficult problem because that objective function is non-differentiable. There are many min and max problems buried inside the function. It is hard to treat, analytically. There is a lot of computation, because they have to solve min and max problems for each generator and each load. It's extremely large-scale. For MISO, they have 5,000 transmission constraints buried in there, about 1,000 generators, and 24 coupled hours. It wasn't clear they had the analytical and computer firepower to solve this problem.

They worked with software vendors, to test several classes of solution techniques. First, they looked at what people would normally think of, sub-gradient dissent methods. That's used in a class of unit commitment algorithms that people solve a similar problem for, if you want to come close to an approximate solution, then you use heuristics to turn it into a unit commitment. MISO did not think this approach would work well. They considered cutting plane methods, where you solve a series of linear programs, and arrive at a test solution point. One gets to see, is that thing optimal? If not, find a cut which cuts it off. Then re-solve. The cutting plane methods did tend to work better, and the analytic center cutting plane appeared to be the most promising of these.

Another concern was how to handle 5,000 transmission constraints? Well, there are 5,000, but in any hour, there are very few that are actually binding in the SCUC/SCED solution. Usually less than ten constraints are binding, in any hour. To reduce the number of transmission constraints, they differentiated between binding and near binding transmission constraints, in the SCUC/SCED solution. This reduced the transmission constraints a lot.

Let's look at an example from November 2007 in the energy-only market. It's a day ahead market with 1,000 generators, 18 constraints with 24 coupled hours to be modeled. MISO was able to solve this problem in 191 iterations, and in 223 seconds. The software was proof of concept software, not production-grade and not optimized for speed. There weren't any performance enhancing techniques. This was truly the slowest way possible to solve this and it took only 223 seconds. Clearly the indications are that they can solve this problem, in practice.

As the computation is run, one can see that the objective function value changes, from iteration to iteration. Initially it is bouncing around, but then settles down, and zooms in to a nice, flat rate, right at the optimal value. The cutting plane methods do this. The sub-gradient methods, which people normally preferred, were never able to get the rates to stop changing, no optimal value would emerge.

The convergence of the dual price vector moves relatively quickly to a price that is usable. It gets to a rate into ten to the minus fourth fairly quickly. That rate, for settlement purposes, given that they are going down to a penny, is very good. The price is able to converge, it is solvable.

What do the Convex Hull Prices look like at the reference load, compared to today's price at the reference load? Average, over the day, the Convex Hull Price is $24. The average of today's price, is about $21.80. It's an increase of 2.2 dollars per megawatt hour. That's the effect of the startup and no load costs being rolled into the prices. The price is stable. It provides a nice bump on those prices from the startup and no load costs.

MISO includes both binding and near binding constraints because they may have to commit a generator to manage a transmission constraint. When they commit that generator, if it is not committed, they may not be able to manage the flow on the constraint, and they'll be over the limit. Once they commit the generator, the flow may come under the limit. The constraint is no longer binding. It's either violated, or not binding, in the SCED approach. SCED would set a zero shadow price on that constraint. Even though MISO is incurring costs to manage the constraint and the commitment, it's setting a zero shadow price, telling the operator that it's free to manage the constraint.

However, the Convex Hull Prices actually roll the costs of committing the unit into the shadow price on that constraint. They can show that that constraint is financially binding, and they will show price separation, between nodes, because of the commitment actions they have to take to manage that constraint. That's one advantage of this approach. In practice they have to take costly action to manage a constraint, but the price under the old system says that it didn't cost anything to manage it. This problem is fixed.

So, MISO is pretty far along with this new system. They're working with LECG to address issues integrating the day ahead and real time markets. They need to address the uplifts arising from those two markets and ensure they're not double-paying anyone. They need to determine which resources and costs should be included when calculating real time prices.

As soon as some small issues are addressed in the software, MISO will start a stakeholder process to go over the theory and practice of this whole approach. They'd like to complete that

Question: Are they using essentially a Mat lab-based researching system? What will it be in production mode? How will they transition this research-grade software into their production system?

Speaker 1: They will probably work to implement a new production-grade version, and implement the solution using industrial-grade solvers like CPLEX. I expect they will also implement techniques to improve the performance, such as hot-starting, constraint-dropping, those types of things.

Question: You discussed congestion management, in the case where a committed generator solves the constraint with its minimum generation position. Will the Convex Hull Price be used to help set where that generator sits on its bid curve? Or will there be a different set of commitment constructions devoid from the price?

Speaker 1: Convex Hull does not change their commitment and dispatch. They determine their prices, after determining how to manage their constraints and dispatch. They're trying to roll in some of the startup and no load costs, into the pricing effects. So, if one has to incur startup and no load costs to manage a constraint, but no incremental energy costs show up, then those startup and no load costs should cause a price separation. It's purely pricing.

Question: So the dispatch instructions generated will still just tell them to stay at their set point minimum, but the pricing for settlement may be higher than that set point minimum suggests.

Speaker 1: Yes, because the startup and no load costs are not covered by those energy prices. Currently they do it via uplift. Instead, people who are benefiting by that startup and no load cost should be the ones to see some price. It's a better pricing signal.

Speaker 2.

This presentation compliments what we just heard. It addresses scarcity pricing and operating reserve demand curves. There have been previous presentations on this. What's new are some real data analyses and numerical comparisons of these systems as opposed to simple abstract theory and formulas. I'll focus primarily on the pricing systems in use at PJM.

I'll also explain how to derive the operating reserve demand curve, in this alternative model. Third, I'll discuss the implementation, because it does present a slightly different kind of computational issue.

There are many names for the pricing system and clever names were confusing people. So now we call the model the Bid-Based Security Constrained Economic Dispatch with Locational Pricing. [Laughter] Embedded in the name, are the properties of the model, so that people don't confuse it, in conversation. Now we have the Convex Hull Pricing model, which is completely transparent to about, what, six of us? [Laughter]

The fundamental problem is when the system is near its capacity limits, and the demand curve intersects the supply on some vertical segment, or close to vertical segment, so that a large part of the market clearing price is the scarcity price. It's not the variable cost of the most expensive plant that's running. The market clearing price should be actually higher. If there were aggressive demand-side bidding in the marketplace, this problem would be solved naturally. Obviously we don't have that for a variety of reasons.

One of the solutions for scarcity pricing and the missing money problem is to adopt something like a locational demand curve, or an operating reserve demand curve. This is a well-known idea. It's been used in NEISO, and the Midwest, as well. The question is what is the proper formulation of that? The real difficulty, is having a principled basis for deriving the numbers. This is significantly different from asking a smart engineer, who knows a lot about the system, to give you a good estimate. That is arguably the system being used today.

While that is good, one would like to do better. When an operator is making the dispatch decision at the start of the hour, they're also committing reserves based on a probabilistic calculation of what could happen over the next 15 minutes. Embedded in that is a series of possible transmission constraints. The expected value of that has to be approximated. The approximation of those expected values is often done with a zonal model. The idea is to have locational operating reserve demand curves at each different location in the grid which interact.

Let's illustrate this by considering New York with its west, east, and south zones. There is an aggregate requirement for operating reserves in the system, as a whole. West, south, and east. There's a separate requirement for reserves in the constrained east area. The prices that result from that are going to be additive. So, if one is providing operating reserves in the east, it contributes to both. The prices are additive for that operating reserve configuration.

There is a transmission interface between the different zones. There's a limit on the interface, and these interact in different ways. Imagine a two-zone model. There are two locations, A and B, and with a transfer limit of 250 megawatts between, and there are generators and load at each end. Further, there's a requirement for 60 megawatts of operating reserves in A plus B. So, this is the whole market. Imagine there's an operating reserve demand curve which is characterized as a penalty function for 40 megawatts, delivered to B, which is just for that region, and then there's reserves in the A region. These can be transferred to B, through the transmission capacity, but it competes with energy transfers, so one has to save some of the transmission capacity for the operating reserve. That's the basic setup.

The price for operating reserves, when one hits the limit, is $500 a megawatt hour. In PJM, that is a cascade model, with reserves in a constrained region, and they also contribute to the total region. There's a total requirement, as opposed to separate requirements in each zone. This is the way this problem is addressed currently.

Let's think about this problem with a second kind of model. One has to integrate the reservation of the interface capacity and derive, not assume, the interaction between the reserves in different locations. Imagine a big system with a constrained region inside that we can call Zone 1. There are reserves inside and outside of Zone 1. There's three different parameters. One is the amount of operating reserves outside, the amount of operating reserves inside, and the amount of the interface transfer capacity. Those are the three parameters for a nested, two-zone model, with a constrained zone.

The key to all of this is the zonal value of expected unserved energy. This value is based on the possibility of a change in the net load, either because load went up or demand, or supply went down. So, a facility goes out, or something like that. If something happens, the system operator quickly re-dispatches the available reserves, in order to meet that change in load. If there aren't enough reserves available, or enough interface capacity available to do that, then the load is curtailed either inside Zone 1, or outside Zone 1.

What we're looking for is the expected value, when curtailed, of the expected unserved energy. Characterizing that function is extremely difficult. However, characterizing the derivatives of that function, assuming it's differentiable is not so difficult. Further, the demand curve is the derivative of these functions. If we know the demand curve, then one could calculate an exact point on the demand curve to characterize the scarcity pricing.

Consider the two levels of curtailment. There is curtailment inside Zone 1, and the rest of the system. One needs to know the probabilities of curtailment and then, to calculate, those probabilities times the value of loss load, That gives one the total value of an increment of reserves, inside the zone; the total value of an increment of reserves outside; and the total value of an increment of interface capacity. Generally one would assume that loss of load inside Zone 1 is more expensive than loss of load outside Zone 1. This becomes a very complex formula for a human, but easy for a computer program. It's just a set of rules one can program to calculate the probability on each one of these paths. Finally, we add those up, to figure out what the demand curve looks like.

If we try to calculate the inverse demand curve, given the reserves in Zone 1, the reserves outside of Zone 1, and the interface capacity, it determines a cost one is willing to pay in order to get one more unit of reserves in Zone 1. One can do the same calculation for the zone, for the elements outside, and for the interface capacity.

There's a number of interesting observations about the nature of this model. There's very strong interaction between these demand curves. The availability of reserves in the constrained region is important for determining the price outside the constrained region. It converges if you raise the interface capacity high enough, so that the prices in the two regions become the same. This is a good thing. It should be true if the model is working correctly. It provides an interface demand curve to derive the value of additional capacity on the interface. Finally, importantly, it has no thresholds. It's not like a penalty comes where, if you have enough reserves, the price goes to zero. It isn't a step demand curve, rather it actually produces a curve.

So how does the model with the PJM demand curves and Cascade model compare to the interface capacity model? If we look at the PJM example from before, and assume their demand curves, set the interface capacity to infinity, so there was no difference, and use the same expected outages and standard deviation for a normal distribution approximation, and the value of loss loads. You can work with this until prices of $500 are produced.

Once the two models are comparable some differences emerge. The differences emerge in key places. The prices on the high end get quite high with the interface market. How does it look if one solves for the problem at a relative low level of demand, the benchmark levels, which were 500 megawatts and 700 megawatts? At this level, in Zone B, the price of energy is $160, and the price of reserves is $70. The interface market design produces prices that are virtually identical, not exactly, but very close to the Cascade model. However, if we increase the load to 925 megawatts in Zone B, the price of reserves, in Zone B, is $500, and the price of energy goes to $875. However, in the interface model, the prices in Zone B are up in the $3500 per megawatt hour, and a similar price for the reserves. In conditions of much higher load, the prices are significantly higher. When the operator is actually curtailing load, it can make a huge difference in the magnitude of the number that comes out. These conditions occur in only a few hours per year, but they can contribute a lot of money to the scarcity pricing process.

If actually implemented hypothetical duration curves to achieve enough to pay for peak charges of $75,000 per megawatt year. Data using actual ISO New England numbers from 2008 show that this produces significantly different overall cash amounts to solve for the missing money problem in the markets. There's a lot of work left to be done on this problem, including getting it a better name, but I'll stop here.

Question: Can you comment on the ramp rates and reserves interaction that that has?

Speaker 2: In the PJM example, there are two kinds of constraints on reserves. One constraint is the aggregate capacity of the plant. So, if you have a 600 megawatt plant, and you produce 500 megawatts of energy, then there is a limit of 100 megawatts of reserves that could come from that plant. In the actual example, most of the plants are constrained by an implicit ramp rate. They can't take more than 40 megawatts of reserves from the plant, even though it might have 100 megawatts of excess capacity. In the numerical examples, when it's the ramp rate that's constraining, then the reserve prices go up and the energy prices don't because it's a scarcity on ramping, not a scarcity on energy. When the ramp rate is no longer binding, and it's the total capacity that matters, then increases in reserve prices get translated directly into increases in energy prices, because it's a tradeoff between energy and reserves. The interaction of both of those things going on at the same time are captured in the example, and would be captured properly in a real world model.

Question: The name that you use here is operating reserve demand curve. Are there different operating reserve demand curves for the different products, or are you summing them all?

Speaker 2: In the Cascade model, which is used in New York, and in the PJM example, there's an operating reserve demand curve for the entire region, which is two, and there's a separate one for the constrained region. They're treated separately, but the prices are additive.

Question: My question is slightly different. There are multiple products. There is spin, supplemental reserve, regular reserve, are those all treated as a single quantity of reserves?

Speaker 2: Ah, I didn't address that. For the sake of the example, I just assumed there's one. So, operating reserves. But, if there is 10-minute versus 30-minute, for example, you would have to treat those as separate products. That's inherently a Cascade structure. A 10-minute reserve is also a 30-minute reserve. So, you do get the additive effect if there's constraints on the 30-minute reserve, the 10-minute reserve can contribute to that. That's pretty straightforward. It's clear, in principle, how to do that.

Then, there's a lot of other products that come, such as voltage reductions, and that is something to be addressed. I've talked to some of the system operators about heuristics for doing that. It's not a show-stopper but the pricing has to be set up properly for those.

Question: Right. It seems like there's an interaction between the different reserve products. So, if the operator is short one megawatt of spin for a five-minute interval, they haven't increased the loss of load probability by much, given the supplemental reserve. Those interrelationships have to be reflected in the pricing.

Speaker 2: Absolutely. This interface model doesn't capture the change in the loss of load probability. Other kinds of products would also have to be integrated. This can be done though, and the derivation from the first principles can lead us to that.

Speaker 3.

I'll discuss the current scarcity pricing changes at PJM. Much of these come out of FERC order 719. The PJM market has a two settlement market. We have nodal pricing, in day ahead and real time. There is a forward capacity market, as well. Stakeholders' discussions concern prices and the forward capacity being locked in and paid for, versus paying a higher scarcity price in real time.

PJM has a scarcity pricing mechanism that is defined for regions of the RTO and the RTO itself. The full RTO can be scarce on energy, or a certain subset can be, as a result of transmission constraint. There are currently six regions. All are delineated by major transmission corridors, 500 KB or greater. They include any generator or any pricing node in those areas with a greater than 5% distribution factor.

The way they initiate scarcity pricing is via an emergency procedure declaration. Generators bid in a portion of their output as emergency load response, voltage reductions, manual load dumps, things like that. Once they've exhausted economic capacity, they dip into the emergency bucket via maximum emergency generation, and declaration of emergency load response. They are the major scarcity triggers. So, anytime they cannot resolve a transmission constraint, or maintain reserves in a region without loading maximum emergency generation, or curtailing emergency demand response, they initiate scarcity pricing.

When they initiate scarcity pricing, they lift offer caps. PJM runs a three-pivotal supplier test every 5 minutes, that tests for structural market power, for generation resources. If the generator has structural market power, they'll run it on its cost based offer, as opposed to a market based offer. Anytime a scarcity condition is a result of a transmission constraint, more often than not, the generators are cost capped because they have structural market power. During these times, it's often the case that PJM has diluted the local market so much by calling on so much supply, that anyone left has market power. Thus they tend to offer cap more and more generators.

During maximum emergency generation they lift the offer caps, and don't offer cap any other incremental generators. That presents a problem. For instance, on August 8, 2007, they had a scarcity event, and lifted offer caps. The price immediately went up to the $1,000 offer cap. Rather than having the smooth transition discussed by the previous speaker, it jumped immediately. There are a lot of generators and demand resources in between the pre-scarcity and post-scarcity price. So, any with a one-hour or two-hour lead time lost the benefit of those prices, and PJM lost the benefit of those prices because the price jumped so quickly and unexpectedly. There wasn't an early enough forward price with a gradually-increasing pricing signal that they could respond, in an equitable manner. If such a curve existed, it could possibly prevent the scarcity condition itself. That is PJM's dynamic today. Prices normally rise straight up to about $1,000 once scarcity pricing comes in.

FERC order 719 came out and it became clear that the PJM response to all of this was not compliant to the 6 criteria, especially reliability, comparable treatment, ensuring demand response, and market power mitigation. In particular, their current approach is bad because market power mitigation disappears. Further, they saw other benefits from having an enhanced method for optimizing reserves and incorporating a gradual price signal. In particular to get at-will resources before an emergency procedure range.

FERC 719 often refers to price formation during reserve shortages. PJM wants to link this new mechanism directly to reserve shortages. The best way to do that is jointly optimizing energy in reserves on the system, and implementing a reserve demand curve. They interject a smoothing mechanism, an operating reserve demand curve, also known as a constraint penalty factor curves in PJM. This jointly optimizes reserves and energy, is a better way to balance system conditions, and has a gradual pricing profile.

If they design it well enough, on the front end, hopefully they can eliminate some issues on the back end, and preclude emergency procedures. The operating reserve demand curve gives them the ability to raise prices commensurate with system conditions, without lifting offer caps. It helps them solve the market power mitigation problem. This is the mechanism they're going forward with, today. This is all still in the stakeholder process, now. They will make a filing with FERC in April.

This new approach will use 10-minute non-synchronized and synchronized reserves as the products to measure the tightening of the system. As they go short on these reserves, they will implement an operating reserve demand curve in real time, and send out pricing signals commensurate with those reserve shortages. It will be a region-based system, probably less complex than what they have today. While there are six regions realistically, they're only really susceptible to one. There's only one prevailing west-east transmission corridor that PJM hits, habitually, during the summertime. The new system would incorporate a single region within the RTO, and then the RTO itself, for the scarcity footprint. An operating reserve demand curve would come in for each product in each region. So, two regions, two products, is four curves.

There would be additivity or substitutability between the products. So, when I talk about 10-minute non-synchronized reserve, the inclusion of that non-synchronized reserve and synchronized reserve builds a product called primary reserve, which is a total 10-minute synchronized and non-synchronized. So, 10-minute synchronized can meet the primary reserve requirement. This results in a dynamic and interaction between the primary and the synchronized reserve prices. It will be inherent in the PJM model we're talking about.

There are some important concerns. First, the inclusion of emergency procedures. So, not necessarily emergency load response. Those are price-based. The larger issue is transmission related emergency procedures like voltage reduction. It's essentially a reduction of load, but there's no real price associated with it. The net effect is an increase in reserves on the system. How does that get addressed? If you increase reserves on an operating reserve demand curve, the price may go down, and that's not the desired result. Manual load dump is a similar problem. Another concern is curtailment of emergency load response. There are some non-convexities in the pricings. Emergency load response may have $1,000 offer prices, but you have to call it two hours before you actually need it. So, what happens with the pricing in the interim? How does one know that the emergency load response is marginal, and can set the price, if it's not directly metered? So, how do you deal with that interaction? They've called a huge chunk of emergency load response, but you don't really know what it's doing or where it is. There's also non-convexities in the reserve commitment prices. In PJM they call on a synchronous condenser to provide synchronized reserves. Those often have min run times. Similar problems with startups, no loads, etc. As they optimize the reserve commitments every five minutes, how do they address an hourly commitment? What if they don't need it, and what if they do? How do you articulate the prices such that the generators that you have now allowed to provide energy, but could have made a higher margin on reserves, have an incentive to provide energy, even though the reserve price is influenced by a non-convexity in the synchronous condenser commitment?

Another big concern is the shape and magnitude of the penalty factor curve, especially as that relates to the maximum price one would see in PJM. Finally, they have a forward capacity market. Some argue, "I paid for this capacity three years ahead of time, and now you're going to jack up the real time energy price and I'll pay it again." There's a serious double payment argument to figure out.

Locational price additivity, and the value of lost load also goes into the shape and magnitude of the demand curve. Theoretically, you want the prices to rise to the value of lost load before you start actually shedding load. When there's an additivity mechanism in the locational prices, but they don't get it, then maybe prices are not high enough. However, if you don't plan for additivity and it occurs, you're potentially charging people double the value of lost load without actually curtailing load itself. This is the discussion that's going on at PJM right now. They have the basic approach done but they're starting to pick off some of these big ticket, ancillary items, before they have the new system worked out.

Question: There are some specific reserve regions where they would do this. What if there is a scarcity condition in a sub-region of the market, that's not defined by those 500 KB systems? It could be a very large area of the system. Would that be covered by these scarcity pricing rules?

Speaker 3: They have this argument going on between the static regions, and then how they would handle dynamic, transient issues on the transmission system, which might be akin to what you're talking about. This approach is for the static region, primarily for this west-to-east transfer flow. At the lower voltage levels, it's not necessarily a large cascading system type issue.

The smaller issues are a circumstantial thing, given where an overload may be located or issue may occur, they may have to define a local region around that. With smaller, localized regions, there are larger market power issues, because the concentration of supply available to alleviate that constraint gets smaller and smaller. That question is a work in progress.

Question: If they had two transmissions, let's say the hull 230 KB system and PEPCO and BG&E were in scarcity, and there was a shortage in reserves. However the binding constraint wasn't on the 500 KB system. There were extra reserves on the 500 KB system. Does this mechanism allow them to reflect what's really going on? They're short of reserves in two hull transmission areas, a very wide range. How would that be handled?

Speaker 3: A good question. The concern is whether maintaining reserves in such a localized region is really a benefit to that region? They're inhibiting their ability to control the transmission facility on its own. I think that example refers to the Con Ed transformer issue on August 8th, right? Under the current mechanism, they wouldn't invoke scarcity in that region. It is very localized, and they can deliver reserves from the larger part of the mid-Atlantic. Reserves along the eastern corridor could deliver to a contingency in those regions. This is still a generally relevant question.

Question: Would you define emergency demand response as PJM uses it?

Speaker 3: In the PJM capacity market, the ability to procure demand response resources to offset our capacity needs has two programs. There's the economic demand response program, they send you a price, and you curtail it as a response to that. Or, two, PJM declares an emergency procedure, and then the generator curtails load. So, the emergency demand response is the latter piece of that.

Speaker 4.

I'll be discussing what is called exceptional dispatch in California. Exceptional dispatch is a term that came into being during the post market redesign and technical upgrade, on March 31st of this year. This is not a new concept. In other RTOs, ISOs, exceptional dispatch is basically known as out of merit, out of sequence, reliability based, manual or operator action.

There's probably three major categories of this. One example is, resources needed to be online for voltage purposes. So, while they run an A/C power flow, it's not an A/C or reactive constrained power flow solution, and therefore, it doesn't guarantee that resources are able to respond to contingencies and reactive needs, and guaranteed to be committed. As a result, they rely on offline studies that define the resources to meet voltage reliability needs.

Second, there are contingencies they call remedial action schemes. So, if the contingency happens, it's not just a matter of re-dispatching to keep a line loading below a certain level, but other things that happen automatically, either load dropping, or generation and runback, that are not part of the market. Reflecting those secondary remedial action schemes into the contingencies as part of the market is not completely achievable.

The last major area are modeling limitations of generator constraints. For instance, there's a real time inability to model forbidden regions in hold periods around resources. So, during those times, exceptional dispatches may be necessary to hold a resource at a certain level, before letting it move through its forbidden region. Or, alternatively, if it was dispatched through this forbidden region, holding it up from moving back down to meet its operating constraints.

From a market perspective, exceptional dispatches are a supplier concern because the lack of transparency and price signals that are occurring as a result of those dispatches. If they're doing exceptional dispatch, and adding additional energy into the system, it may be depressing prices for the rest of the system. Further, if they're committing certain resources for online capacity needs, there may be a missing product that needs to be incorporated into the market, and priced explicitly. From the demand side the perspective is that exceptional dispatches after the day ahead market are adding additional energy into the system, that wasn't incorporated into the day-ahead market itself. There's a concern for price signals from exceptional dispatch. Exceptional dispatches do not explicitly set prices but may influence prices.

In terms of settlement, depending on the reason for the exceptional dispatches, the costs are allocated either to the participating transmission owner, if it's addressing a localized transmission model issue. If it's not a local transmission model issue, then it will be allocated to the net negative deviation, and to meter demand, in two tiers. When I define cost, I'm talking about the excess cost, because, the exceptional dispatched energy is paid market prices, and then there is uplift for the excess costs, to make it hull to either its minimum load, or to its bid in energy that it was dispatched up to.

The new market in California has had a learning curve to determine how the new market was actually performing, to achieve and address all of the system constraints. The frequency of exceptional dispatch has been a concern. About two months ago, a strike team was developed to mechanisms to address exceptional dispatches. They are analyzing the root causes of the exceptional dispatches, and trying to incorporate additional constraints into the system. This is a challenge, because incorporating voltage constraints means converting to flow-based constraints.

In July, to address a large amount of pre-day ahead exceptional dispatches, they said we're not going to do any pre-day ahead commitments. Only specific cases where they know the market would not start the unit would be incorporated. Many resources that normally would have been exceptional ended up in the market.

They also identified a significant category of commitments related to two specific procedures, that needed to be online. The capacity could either be already dispatched for energy, or it could be unloaded capacity. Either way it needed to be available to address contingency-based voltage concerns in the area. If they tried to enforce that constraint in the integrated forward market by putting in an energy constraint, they would force the units to be loaded up at the full energy level that the constraint required. These resources just needed to be online, and a certain amount of capacity online. Around July 24th, they shifted the process, to allow the market to run, reducing the amount of pre-day ahead commitment. They used residual unit commitment, and they were able to enforce a constraint that said a certain amount of online capacity needs to be online, on a group of units. This new approach created a significant reduction in exceptional dispatches.

The next problem is that, if they do it post integrated forward market, in the day ahead, the minimum load energy that is being committed in the residual unit commitment, is not being incorporated back into the market. There's still additional energy that's not being priced, nor incorporated into the market itself. It may depress prices, when you go into real time. The next challenge is to add additional constraints into the integrated forward market to get those commitments achieved, in the integrated forward market.

Now, that won't solve the problem either, because there's a situation where you have commitment, at minimum load, but the prices may still be insufficient to fully cover the minimum load and startup costs. The next step is how to price it? Do they need additional products to price that capacity? By the way, this is not covered by spinning and non-spinning reserve, which is a 10-minute product. This would be a different product.

The ISO has reduced its dependency on exceptional dispatches consistently since they began to address the problem. In the beginning, it was relatively high, in the two to three percent range. Now it's generally below the one percent range. Comparatively, the NE ISO is still around 2-3 percent.

They're considering whether to use additional residual unit commitment constraints and complex modeling within the integrated forward market to help reduce these issues further. Also an additional constraint equation that would dictate a minimum amount of online capacity, based on a certain group of units. That would get units on and committed, but wouldn't necessarily affect and create a price for those commitments. For the forbidden region situation, moving to multistage generation modeling has been discussed. This provides a more representative modeling of the constraints of combined cycle resources, so that they can avoid having to manually dispatch a resource, or hold a dispatch on a resource.

Some of the reasons for additional exceptional dispatch is to bridge end of day commitments, so if they need a resource the following day, they may need to give it a dispatch or a commitment for two hours at the end of the current day. They are looking at multi-day optimization, a commitment over two days, they can get rid of those bridging issues. It's a full-on effort in California, and improving considerably.

Question: The convex hull price is obviously not the marginal cost of energy. Consider a scenario where the wind is blowing really hard, and it's good if people consume, because the marginal price is very low, and you want batteries and demand response, who are not actually in the market but are getting a price signal, how do you treat them? A whole bunch of fossil generators will be sitting at min load, waiting for the wind to die, so we want people to consume. However, the convex hull price would probably be at the price of the fossil generators that are waiting, sitting at their min load. How does convex hull integrate all these new devices and set the right incentives.

Speaker 1: Well, the convex hull price is an ex post price. They can take into account what the wind was, and if there was too much generation committed and sitting at eco min, they could set it so it doesn't end up as uplift. It may not show up in the convex hull price. Just because the operator made a bad commitment decision, and committed everything, doesn't mean that it would be in the convex hull price. The pricing system could account for conditions and determine a good blend of things that would have been committed.

Second, there is a disconnect in terms of just sending a price signal, and having the loads show up without participating in the market, directly. How do we know that somebody is a load, responding to a price signal, versus a price insensitive load, and they've committed a unit for? It's not clear that the convex hull price would apply to some and others would get a lower price. For instance, if the CHP was $40, and they said that they are willing to pay $35, and we tell them to consume, we could end up giving them $5 back, because that would be an uplift. The operator asked them to do something that was not economic, from their profit maximizing point of view. Does that help?

Question: Ideally, you'd want everybody bidding into the market. However, it's impractical to have your refrigerator, your car charging battery, or your dryer bidding into the market. Presumably we do want them responding to price signals.

Speaker 1: There has to be a way to differentiate between price insensitive load versus someone showing up because the price is low. That's a challenge for the future.

Question: In PJM, I'm confused about the relationship between the mandate to mitigate market power, and the mandate to put in place proper scarcity pricing. Does this keep market power generators who will be paid cost from operating in an event with scarcity pricing. Is there cost-revenue gap because only some of the suppliers are paid the scarcity price? Does it affect the price that the consumer would pay, which would be counterproductive to having scarcity pricing? \Or is this a fig leaf, that we have to come up with, for continued political support for this? What is the reality of trying to make these conflicting objectives work out?

Speaker 3: By conflicting objectives, you're talking about maintaining market power mitigation, but getting prices up during a scarcity event?

Question: Well, I thought the operating reserve demand curve approach would set the price high, where it needs to be. If you're having to shed load, it goes all the way to VOLL, say $10,000 a megawatt hour. Everybody ought to get that price but the market power generators just get cost?

Speaker 3: It's the market clearing price market, it's not pay as bid. So, if a generator is operating on cost, the operator still pays market clearing price and they get the gap between. The real dynamic is how does the operator account for revenues on capacity resources? So, there are resources receiving a capacity payment, and they're paid to be there, for when there are events like this. Is the operator double-paying them, by elevating the price commensurate with a scarcity condition in real time at the same time as they're getting a fixed cost capacity payment? There is an interaction there, they are potentially charging load twice, for the same product.

PJM addresses it by a real time offset. So, if they commit your generator for 100 megawatts of capacity, but it runs to 108 megawatts in real time, for those last eight megawatts, you can retain scarcity rates, because the operator wasn't depending on those eight megawatts. That gives the incentive for generators in real time to respond to the price that's set forward. Does this answer your question?

Question: No. But you're causing new questions to arise. Maybe I need to go back in the queue. [Laughter] To clarify, a generator with market power does get the scarcity price? Everybody gets market clearing price?

Speaker 3: Yes.

Question: To the other point, when you buy capacity, the capacity you're required to buy doesn't guarantee there will never be an outage. It's subject to some probability. Why would it be efficient, if you're in an outage situation, to give them money back? Shouldn't everybody pay the scarcity price, regardless of whether you paid for capacity or not?

Speaker 3: There are two sides to that argument. One argument is, these resources are paid for already, whether the system is scarce or not. I already paid for it.

The other side argues that capacity is being purchased in expectation of a peak load day. The transmission system probability that it will be in service is an expectation. If those expectations don't come to fruition, they are in a scenario where they need to reach for stuff that hasn't been planned for. That's what scarcity prices are meant to do. It's hard to say which interpretation is correct.

Question: In terms of the Convex Hull process, the commitment process can be associated with energy congestion, via operating reserve constraints. Regulation can factor into the prices for energy. How will the process deal with the price convergence issues, and getting real time prices under the same conditions, to pick up commitment concerns. When everything's already committed, everything's already done, and you're dealing with a real time SCED solution that isn't making those commitment decisions. Similarly, there are temporal issues associated with the hour ahead scheduling of external transactions, the hour ahead and 30-minute commitments of resources, that are all done prior to the SCED and real time. How do those factor into the real time pricing of the Convex Hull?

Speaker 1: They are currently working on that to determine what costs should be included in the real time Convex Hull Price? For example, quick start CT commitments should be there, because those are happening close to real time. The RAC process, the reliability commitment, should probably be included. They're considering whether to have the startup and no load cost from the day ahead. What happens if they can de-commit units? That should be addressed. All these concerns are being worked through currently.

Question: My understanding of the current proposal for the PJM scarcity pricing is that it's a real time only approach. In the context of a hot week, or a hot two-week period, where one can see these things coming in the day ahead, how are the convergence issues for day ahead market going to work? One can almost guarantee they're going to be in scarcity pricing in real time, but there's no mechanism to set those prices day ahead.

Speaker 3: PJM prices in the day ahead are not based on load forecast. They're based on clear demand. There is so much price sensitive demand in the day ahead market, that when prices got high enough, demand would, frankly, just stop buying. The mentality, from PJM and the stakeholders, has always been that day ahead is a market based mechanism. So, if they're going to hit scarcity, and real time is not going to converge with day ahead where you're not scarce - that's an issue. It's basically because of price sensitivity. People are willing to take a risk in real time, and buy a real time position, hoping that they don't go into scarcity. You're question is a concern, but so far there is no play to do anything about it.

Question: I have a question in respect to moving from the day ahead to the real time market implementation. The real time market incorporates so many more factors than the day ahead. If they don't incorporate all of those other factors in the pricing scheme, could it conceivably increase uplift, and price volatility? So, in effect, they get quite the opposite result?

Speaker 1: I'm not sure what other factors you're considering. They are dispatching real time to meet real time requirements, and they're seeing the real time price being lower than day ahead, because they may be committing additional units, to provide added flexibility. They're sitting at eco min. It looks like it might be depressing price, a bit. If they can sit down and say, "Here is our requirement, in real time. Here is what we're trying to do. Here is where our load is going. Let's look at what set of units we have, that we either committed, in the RAC process, and try to say, should those have been committed, and should their price be incorporated in the real time CHP, same with short run CT, or short commitment time CTs, including those costs in CHP?" If anything, that should help raise the price, in real time, a little bit, and would help improve price convergence. I'm not quite sure what other factors you're thinking about.

Question: I'm referencing the ongoing discussions in the RSG Task Force. They are identifying the factors that cause RSG, and need to price them accordingly. There's a long laundry list of potential causes and if they are pricing correctly, those causes should be incorporated into the market.

Speaker 1: If they're going to look at CHP, in real time, look at how the load actually picked up, they can determine over the course of the hour or so, it appears to be optimal to have committed these units. Their startup and no load should be incorporated in the price. In essence, by looking at how the load evolved, and in pricing it, they should be taking those factors into account, in their pricing mechanism.

I don't know if it's being handled to the same extent, today, because they are committing units for head room, and load following, and so on. That's based on operator judgment. Here, they are saying, let's let the pricing engine see how the load and everything was evolving, and determine what costs should be incorporated in the price. I would think it would only improve the situation. I don't see how it would harm it.

Question: Are you suggesting that the Convex Hull Pricing will do away with the need for something like head room and operator judgment?

Speaker 1: No, they're not changing their commitment dispatch. They're trying to price it. They're trying to say, which of the costs they're incurring should be reflected in the price? Based on what they're seeing, how they see things evolving, which costs should be reflected in the price? They're not going back and changing our commitment and dispatch. They're saying, what costs should be reflected in the price, and what should be reflected in uplift? If we had an operator go insane and commit every CT, well fine. They would not reflect that in the price.

Question: We're discussing perfect prices. Consider the following situation. First, the Convex Hull solution showed a difference in prices. Convex hull is appropriately incorporating the startup and no load in the pricing, but the existing systems don't. We heard about scarcity pricing from others, and in order to get the operating reserve demand curve set properly, we really need to know the value of lost load. There's a large amount of uncertainty associated with what that value is. One might know what the shapes of the curves are, reasonably, but where to set the value is hard to get a handle on. The real concern is finding a smoother transition between scarcity and non-scarcity conditions.

We've also heard about exceptional dispatch being used to satisfy various operational considerations that aren't being properly captured in the market. Now, one of the solutions is to use residual unit commitment, which is a capacity commitment and optimization routine. This loses a lot of the efficiencies, compared to the way the real time and day ahead market work, to solve these operational constraints.

These are a mishmash of attempted market solutions, with operational constraints that are sometimes interfering with market solutions. So, my real question is are we anywhere near getting perfect prices? It's almost as if it doesn't matter exactly what the prices are, as long as we're in the neighborhood, things are going to be OK. Is that really the way it works?

Speaker 2: It's a very good question, and it is partly an empirical question. I would propose two tests that would be helpful, here. One is, if we implement convex hull, and we look, ex post, at the going forward capacity market prices, the dollars flowing through the capacity market should be relatively small. Zero, would be an appealing answer. Now, there is a little difficulty in doing that, because of the difference between planning reserve requirements and the value of lost load implications, and so forth. The implied value of lost load in the planning reserve requirements is on the order of $250 to $500,000 per megawatt hour, and the uncertainty about the value of loss load is somewhere between $5,000 and $20,000 per megawatt hour. There is an order of magnitude difference between those two things. The capacity price wouldn't get to zero until that uncertainty is addressed, but the prices should get very small.

A second test would be that the difference between the uplift that's actually paid, and the minimum uplift that would be calculated with the pricing model, should be zero. That should be the target. If they were dispatching and pricing everything, consistently, they should be getting very good dispatches. It doesn't mean there's no uplift, it's just the incremental effect of that would be smaller and smaller.

How far away is the system right now? On the scarcity pricing story, we're way off, I think one graph I showed was around $75,000 a year. They're probably collecting a third or so of the implied scarcity prices, through the energy market. The other two-thirds is coming through the capacity market. That is not a good situation. It has implications for actual operations, and incentives for people to do things. The incentives on the demand side could be strongly affected, when you start doing this. If it's done right it will stimulate more demand investment because the prices will be right. Overall, things are far better than when there was a single price for PJM for energy. This approach is worth doing, and should be done soon. From my perspective, the scarcity pricing piece is the most important – it's the largest cost numerically and will have the largest impact.

Speaker 1: The work on scarcity pricing is needed. When MISO was getting ready to start their ASM market, they were putting in demand curves for regulation. Whenever they started running numerical tests, they'd find they were short a little bit of regulation. It was pricing at $1100, and that price would bleed through to the energy prices. So, every now and then, they get these tremendous price spikes.

It was clear it was not the cost of being short a megawatt or so of regulation. They needed an approach that was less ad hoc and more accurate. They said, well, what were the actions an operator would take, if they're short regulation? They're going to commit a CT, so what's the average cost of committing and running a CT for an hour? Let's use that. Things improved, the price settled down. However, that's not an integrated solution, where every piece fits together. We need scarcity curves and pricing signals where all the pieces fit together. There are still occasional times when they get volatility – price spikes and drops.

Right now, the markets are good. They are getting decent results. But, clearly, they can be improved. They won't become perfect but they will be improved.

Speaker 3: If we design pricing well enough, on the front end, you don't have to worry about the back end. That's the tact PJM has taken, and part of the reason is because the value of loss load is so subjective. No one really knows what it is. Ultimately, it is a value that we need, to adequately control the system, and set prices commensurate with a condition to elicit further response from out of market resources. There's also a side of social acceptability. Value of lost load might be five or six figures long and that may not be socially acceptable, to people. So, that needs to be balanced, in the effort to perfect pricing. That may be a hump in the road that takes a while to get past, before an operator gets to a single perfect price, where RSG is zero, and uplift payments are zero. There's a social side of this thing, where high numbers, that would be required to get to this single perfect price, are not currently realistic.

Speaker 4: My take on this involves three steps. Step one, get everything modeled, and the constraints modeled, to the extent you possibly can. Without that, you leave the possibility of things that are done outside the market. Then, with those constraints, assess are there a new set of products that are missing and need to be incorporated? If so, then a concept like the convex hull solution may be a good approach toward getting better, if not perfect, prices.

Given all this, we need to remember that volatility is not always bad. As long as it's reflective of the constraints and the conditions, then the prices are probably more appropriate than we are giving them credit for.

Speaker 3: If we finally do find perfect prices, the political arena won't allow us to use them, anyway. [Laughter] We've heard about this dynamic between scarcity prices and capacity prices. Capacity is planned for in expectation. However, unless you have perfect foresight, you can't necessarily set a capacity price that, or, you can't plan for scarcity revenues, going forward. So, that clearly creates some volatility. We'll never have perfect foresight but any improvements that we can do, obviously, provide immense benefits.

Speaker 2: What's politically possible, I think, is much a broader range than most people are willing to admit. The existing design of the RTOs, and markets, and what we're trying to improve and fix, was previously described as politically impossible. People said it could not be done but it got done. I don't accept the notion that it's impossible.

Some things are more difficult than others. For instance with VOLL, there's a difference between heterogeneity, and uncertainty in the value of loss load. We may all have different views about individual values of lost load, and then there's uncertainty about it. For the operating reserve demand curve, they identify the groups that are going to be involuntarily curtailed. That inherently involves averaging. right? That removes the heterogeneity of the group. It doesn't remove the fundamental uncertainty, but it does reduce uncertainty over the average of the group. The uncertainty around the average is much less than the uncertainty around the individuals, and substantially less than the heterogeneity, the heterogeneity is irrelevant. That problem is overstated. On a city street my next door neighbor and I have very different values of lost load. She's a retired lady who doesn't worry about her fiber optic system, coming into the house, and I do. We have different values of lost load. But what's relevant is the average of the two of us, not mine or hers.

Question: I have more on scarcity pricing. We've heard about a constraint based, incorporating operating reserves formula. I'm always cautious about trying to guess, in advance, which regions are going to have scarcity pricing. The concern about market power is real, but if you have large regions, like a whole transmission area in a voltage reduction or generators are being asked to operate on their emergency maximums, that is a scarcity condition, even if there might be reserves somewhere else in the system. Does PJM believe that it has addressed that problem? Does convex hull address it?

Speaker 3: In PJM there's a balance between the size and number of regions. You could go down to a nodal level. Currently they've tried to find a region that addresses the majority of the actual issues on the system. Large west-to-east constraints on a hot day, those kinds of things. It's a region that is eastern enough and large enough that they don't run into market power issues, and it addresses the large, prevailing west-to-east power flow issues.

They have a macro approach, at some point, there's diminishing returns on maintaining reserves in such a small localized region. There are market power issues. This addresses a majority of the transmission constraints that they hit. They have discussed reserving the ability to create smaller, localized regions, maybe on a day-to-day, week-by-week basis, depending on transient issues on the transmission system. If a hurricane went through part of the system, and knocked two 500 KB towers down. For issues like that, they need flexibility.

Question: My concern isn't about relying on the reserve curves. Is there another mechanism to get the prices better, so that you're not mitigating.

Speaker 3: The only answer is to let the emergency capacity set the price. Without any kind of an outside intervention, or a reserve curve, the emergency capacity has to be able to set the price.

Speaker 2: There's several different issues, here. One is market power. The operating reserve demand curve, if it's representing the best estimate of opportunity costs, provides a mechanism for disentangling scarcity price versus market power rent. If the scarcity price is set through the operating reserve demand curve, then bid caps on the offers don't cost anything, and the market power problem goes away. The missing money problem is gone.

The second question is about multiple zones. This interface model is more adaptable to that for a variety of reasons. It requires an ex ante calculation of the operating reserve value. They look at the value at the start of the dispatch period, and then price them, ex post. Maybe during that period something happens, emergencies. If a transformer is down, there's constraints, and they're holding things off, for voltage problems. They could represent by outlining a region, inside and outside. The system operator has to specify what the interface limit is, the transfer capacity, and identify the exact region.

Once they identify the region, the transfer capacity, the rest is a calculation. It's not hard to do. You get this demand curve, no step function. It's more robust. Having the capability to do regions like this is very good.

Question: What is a perfect price? The energy industry is complicated, in terms of its total number of degrees of freedom. All that information equals a large amount of entropy. A lot of content comes from the carrier frequency price signal. The most efficient information, and the most correct, inherently has a lot of volatility. The volatility needs to be meaningful. All of the different elements of the system that change, and local scarcity issues, and local supply and demand concerns, and longer term uncertainty about whether they're going to be there or not. The need for communicating a lot of volatility is tremendous. Without it, customers, and marketers can't get enough information about the system, and how it's dispatched, to make appropriate decisions, or the right level of decisions. Convex hull addresses some of that gap and allows information content to be passed through to customers. Alternately, there's political and operational resistance. Many want information to be thrown out, passed on, cut back, averaged out, or made simpler. These create noise in the prices. Some of it's just reflecting bad rules, or operator discretion, that tends to interact with rules in unexpected ways. Alternately if we want transparent information content, and transfer, then it's a question of how to ensure the right balance between information content, real information in the pricing, so the customers can make efficient decisions, about how to change their short-term, and immediate decisions. Simultaneously, how do we also allow all the content necessary for long-term decisions, investment, innovation, to get the right view of the complexity of the system? I am concerned about a very simple, perfect price, that's very flat, and very averaged, and devoid of information.

Speaker 2: This is a cost-benefit tradeoff. Let's prioritize a list. The first thing is to charge for the energy. Then, charge for the energy, with different prices at different times. Then add different locations, and that's LMP. What about reactive power? That's one we still haven't done a good job with. We also haven't dealt with scarcity pricing and the missing money problem. We know what the problem is, but it's politically impossible to fix that, so we'll have a capacity market solution. There is this tradeoff. We're much closer to an ideal point but not there yet.

At some point, you should stop. Should we be trying to do cost attribution for black start capability? I don't think so. Some things we put in an average uplift. Now there's an endpoint. We aren't there yet, but we're closer.

Speaker 1: I agree, volatility is good. However, it depends on what's causing the volatility. We don't want an instability built into the market. The price response is almost instantaneous. If we expect people to respond, ten minutes from now, to a five minute ago price signal, we could end up with a positive feedback loop, which is driving some instability. If MISO has a high energy price, let's say, and PJM has a low energy price, people will try to schedule a lot more imports into MISO's system, and that causes instability. Should they limit the ramp that can occur, to help dampen that? More demand response will fix a lot of these issues. The system has to stay stable. Volatility is good, but not instability. Will other things help improve the situation? For instance, imports and exports between MISO and PJM. Could they see if market participants tell them, if the price difference is X, I'm willing to increase my import and export by so much for the next five, next ten minutes off. Similarly with the RTOs, they can say here's where our prices are going to be. Yes, we should schedule this, or no, we shouldn't. In essence, let the market participants participate in the market, but don't make them guess, based on what happened in the past. Something similar could be done with demand response. An LSE could give a forecast of their price responsive demand. The RTO could set the price, based on that, for their ten-minute out schedule, and post that price. They could see if people responded with the forecast built in. The RTO has to ensure that the pricing mechanisms do not have negative feedback built in that promotes instability.

Speaker 3: The perfect price doesn't need to be flat. There needs to be volatility in there. It needs to take into account marketers and their behavior. Imports and Exports between RTOs have to be incorporated. In general, the operators have to send prices that incent behavior.

Question: Generally we need to improve the total amount of information that is being incorporated into the price. Incorporating additional constraints will help, but we're dealing with intra-temporal constraints that don't get incorporated into the marginal prices. Convex hull may be a benefit but it may also create countersignals where the price is higher than the resource is marginal.

Question: With regard to exceptional dispatch as this market rule changes, and also transmission upgrades, which are PTO [primary transmission operator] dependent. First, is the California ISO looking to identify which transmission upgrades might be helpful? Or does the PTO determine this by itself? How does this get incorporated into the exceptional dispatch?

Speaker 4: The ISO strike team is not proposing or identifying projects, but is providing feedback to the ISO planning process. This will help guide and identify projects that will be built by PTOs.

Question: So, if I'm understanding that, it's not so much just a survey of what the PTOs are maybe doing for other reasons, such as reliability criteria, but it's asking them, what might help the problem, taking those proposals, and feeding them back into the planning process?

Speaker 4: Right. There may be stuff that's already in the queue, for work. We want to consider those. We don't want to repeat those. But there may be some additional things, constraints that are now arising, leading to exceptional dispatch, that may be able to be done, and we would guide, and hopefully have the information clear enough, what's driving the exceptional dispatch, that would help guide our planners, and guide the planning process, and guide, ultimately, the PTOs, to do the upgrades necessary to eliminate the issue.

Question: Will the planning criteria point to a transmission upgrade, or another solution?

Speaker 4: Their planning process is prepared to do that. However, it needs to look further out, and also look for alternatives. It's not just transmission upgrades, but also the best alternative. Right now, it is about a one-year look ahead. And some of these things need to get out further.

Question: Is PJM going to redefine the product in the capacity market, as a result of the demand curves? One could argue that today's purchase is allows demand to purchase at a price below $1,000, since that's their cap. Will they redefine the capacity market product, to reflect the new demand curves?

Speaker 3: They're not planning on it, when the capacity market was put together, it wasn't put together with the sense that it's a financial call option.

Question: But, in effect, it is.

Speaker 3: It is, but what's the price of the call option? It's not necessarily $1,000.

Question: Well, there's some network effects. If it was a single node, it's $1,000.

Speaker 3: The simple answer is they're not looking to redefine it.

Question: Second, suppose pump storage or batteries were willing to participate in the market. Ideally, they wouldn't bid in prices, but they would simply bid in a capacity that they have to generate with ramp rates. How would that be priced, in the convex hull approach?

Speaker 1: PJM does have to give storage some price information, because it tends to be big, and long, long term. Batteries, fly wheels, they tend to be shorter. So, I guess I might view them as being a little different. In terms of Convex Hull Pricing it's not clear how they would be integrated.

Speaker 2: Consider an imaginary pump storage technology. It absorbs energy sometimes, and discharges energy at other times, and it has a more than 24-hour horizon, so it's got a value of energy, at the end of the period, and has a cost of absorbing, and discharging. So, what they would bid in is the cost of absorbing, discharging, and the value of energy at the end of the day. That would have to be from their business judgment about what it's actually worth. Then, the rest of it is a convex problem, and it's completely straightforward to include in the model. Solve the optimization problem, and it's determined whether it's in or out. It's fairly simple.

Question: And what's the price?

Speaker 2: Whatever the convex hull price is.

Question: But the algorithm is going to dispatch them at the LMP and they may lose money.

Speaker 2: Right. And then they get an uplift, if that's the case.

Speaker 1: Except, that would require changes, dispatching algorithms.

Speaker 2: Well, if you took the dispatch out, and there was a dispatch algorithm that gave a less than optimal solution to get them to do it, then there would be an uplift payment which would be larger. That would be the difference between optimal dispatch, which is technology, versus what they actually did. It's not a hard problem.

Question: But the make whole payment only lets them break even.

Speaker 2: The make whole is based on the optimal dispatch of the technology. They should end up better.

Question: It seems like, having startup and no load costs incorporated inefficiently into spot prices, is a problem, across all the ISOs. Would other ISOs look at it, if it works in MISO?

Speaker 3: It's definitely an interesting concept. My initial reaction, is that you want market participants to respond to dispatch and not price, which is true today. However, now the price and the dispatch aren't going to align, and how do you stop people from chasing? It sounds like it's good, in concept, but it would probably take a lot of training, on the stakeholder side, to get people to not chase price. The price, now, includes something more than incremental costs.

Speaker 4: I suspect California ISO would also consider it. There's a concern with it being ex post, you still have dispatches that are being performed, and, at some point, there's the dispatch signals that come out with the dispatch. Those will still be marginal prices. It will help eliminate some of the uplifts.

On the other side, when those higher prices are there, are there now going to be additional opportunity costs, because a resource now sees a higher price, and says, I should have been dispatched higher. What's the impact of that? Also, the whole convergence between day ahead and real time is needs to be thought through.

Session Two.
Smart Grid and Demand Response: Implementation and Pricing Issues

The possible smart technologies and business models are expanding faster than knowledge about what works in practice. Critical issues can arise in implementation of smart grid applications and in getting the price signals right. What technology is actually being deployed and what have the results been to date? How have customers responded to the "smart grid" related offers? To what kinds of technology are they receptive and to what types is more resistance being encountered? Are customers more receptive where they have more control or are they willing to be accepting to centralized demand response controls?

What pricing and other incentives are being offered to customers? Which offers have proven successful in attracting positive responses, and which have proven to be less successful? What types of consumer education are being carried out to encourage customers to avail themselves of the opportunities they are being offered? How is the pricing of "smart grid" related offerings being designed and implemented? What types of monitoring arrangements are being put in place to fully evaluate the effectiveness of the investments being offered? What criteria should we be using to determine whether smart grid investment has proven its worth and how much experience will we need to have to be able to fully learn the answer to that question?

Moderator: I'm going to first give you a sense of what's happening with the smart grid in Texas. Sometimes it's about Smart Grid and renewables, other times it's Smart Grid and demand response. Texas is creating a green grid and renewable system. They have approximately 8,000 megawatts of wind energy on the grid now.

The TDUs in Dallas and Center Point in Houston are presently deploying advance meters. It's about 3 ½ million and about 2 ½ million respectively, AEP has an application for about a million. They hope that at one point plug in electric vehicles can plug in to the smart meters at night, taking advantage of the wind blowing at night. This will levelize the load. That's just one way in which the Smart Grid is being implemented.

Speaker 1.

I'm going to describe the broad landscape of this topic. One of the topics, demand response, is nothing new for the power sector. It's been in use since the 1970s, when interruptible rates were instituted for the largest of customers. The concept remains the same today. It's an end user getting a lower rate or an incentive payment, in exchange for agreeing to reduce their electricity use at the request of the grid operator or the utility. The concept is the same today, but today but there are more types of demand response programs, and technology for its expansion.

There are some motivations underlying the implementation of these two concepts. First is a need for more flexibility in the grid. Second is a desire to reduce the carbon footprint of the power sector. And third is a push to minimize cost.

On the supply side, more renewable power needs to get integrated into the grid. On the demand side of the grid, there is a potential need to integrate a large fleet of plug in hybrid and electric vehicles. Second, both demand response and smart grid depend on each other. Best practices in demand response programs are hard to determine. The compensation levels for the demand side participants are pretty diverse. Wholesale electricity markets that have demand compete side by side with supply are starting to shed some light on the price sensitivity of those resources. While technology can address a lot of issues around demand response programs, it can't fix everything, in particular politics.

There is a lot of change going on in the power sector. Renewables are intermittent and not as predictable as conventional power supply. It is more challenging for the grid operator. Plug in hybrids will be introduced here as early as next year. A mass market for these vehicles is longer off. The mass market, flexibility to plug in the car in a variety of locations at any time, and higher voltages applying faster charging times will all be a real issue for load management. The smart grid can give the utilities a toolbox for a large fleet of electric vehicles, and also help manage the fluctuations with renewable power. That's the broad picture.

Demand Response needs the enabling technology of smart grid to allow a time of use rate, to give customers more knowledge of their own power use. However, the reverse is also true. In the rate cases and business cases before public utility commissions, a common thread is that substantial savings for the smart grid programs and AMI [Advanced Metering Infrastructure] applications come from demand response and efficiency savings. While the operational savings can account for a lot of the smart grid business case, the efficiency and demand response savings are required in every case I've seen.

AMI penetrations are at about 5% meter penetration. It's hard to keep track of the deployments, there's no clearinghouse for this information. Between the full deployments and pilot programs and assume that they go forward, the U.S. will have close to 50% AMI penetration by the middle of the next decade.

Cost minimization is a big motivator to expand demand response. However, it's very hard to determine best practices. There are clearing price levels from the various Northeast capacity markets where demand resources compete side by side with generation resources. There's also regulated utility programs like the FP&L on-call program, a central A/C cycling program, the PacifiCorp irrigation load program, and PG&E's program for larger interruptible customers. The payments are all over the map, there's no consensus.

Many utilities benchmark competition to demand resources against the cost of installing a new combustion turbine [CT]. However, the price one would pay to a demand side resource really has nothing to do with the cost of a CT. An end-use customer doesn't know what a CT costs to put in. The value of demand response to the end user is actually the value of lost load, really. That's not at all transparent. Currently, there are some really low clearing prices in some of the capacity markets, but there's still a lot of demand response coming into the market. It depends on specific loads. For example, it is a lot cheaper to convince a farmer in the Pacific Northwest to curtail their irrigation pumps for an hour during the growing season than to shut down a trading floor during business hours on Wall Street. Clearly, AMI and other technologies can address the fact that most customers today see very flat and non-fluctuating power prices that do not reflect the changes in the cost of actually producing and delivering power.

Measurement and verification are a big hurdle in a lot of program administration. That can get fixed with technology. There is the political difficulty of mandating certain residential customers to time of use rates. Nobody wants to put Grandma on a critical peak plan that's going to raise her electric bill. Another concern is seams between wholesale and retail markets in markets without retail choice. It can be difficult, if not illegal, to aggregate retail customers and have them participate in a wholesale market. Demand response is really ultimately about expanding into residential customer bases. The loads most conducive to demand response are central A/C loads. This is not asking people to shift to an off peak time. A utility will lose kilowatt hour sales. It's at odds with the way most utilities are compensated today which is volume based compensation. This requires decoupling or alternative calculations to encourage the utility to pursue these programs.

Question: What's the difference between operational savings, and total benefits?

Speaker 1: Operational benefits are things like reduced cost for meter reading, the remote connect/disconnect. You don't have to roll a truck to shut off service and put on service, particularly important in an area with a lot of apartments. The other benefits accrue more to customers and not directly to the utility, like demand response programs and energy efficiencies. This would be a reduction in overall kilowatt hour sales, that benefits customers, not the utility directly. It's stuff the utility doesn't directly see.

Speaker 2.

I will first talk about what the smart grid is, because definition aspects are important. Then I'll discuss the activities of Southern California Edison in California to get a sense of their particular smart grid activities, and also how they price demand response.

There are a lot of definitions of Smart Grid, but most people divide it into two categories. One is providing information to the utilities and consumers concerning electricity use, prices, and then potentially in the future being able to control or have communication between appliances and the utility or the customer. This includes controlling appliances to promote economic efficiency, running them when prices are low and curtailing them when the prices are high.

The other aspect of smart grid is improving reliability and security by sensing problems on the system when there are voltage problems, seeing the power flow, and being able to implement fast and automatic protective responses.

Most people think of the first category, but the reliability is also an important component. The focus so far has been on smart meters, home area networks, and communication technology to accomplish the first objective.

With respect to the reliability concerns, the California commission recently established a smart grid rule to encourage other aspects of a smart grid. They have already adopted or approved AMI meters for all three utilities. They are beyond that stage right now. There will be another rule making for alternative fuel to determine what kind of additions to the system are needed to accommodate electric vehicles. This is important because every time you add an electric vehicle to a household, it's like adding a new house. This could have a lot of impact on the system, because additional transformation is needed, particularly battery technology.

Another component of Edison's [SCE, Southern California Edison] smart grid strategy is for renewable and distributed energy integration. They are focusing on the ability to store wind energy, because wind usually blows in the off peak, and it is needed at the peak period. At the Tehachapi wind area they are looking at utility scaled lithium ion batteries for storing wind resources.

In terms of grid control and asset optimization they are examining synchronized phase measurement systems. They are also looking at a smaller scale circuit of the future, named the Avanti circuit,. It has a lot of different technology placed on the system in to look at system conditions.

Edison recently filed an application under the stimulus act for a smart grid demonstration in Irvine, it's a faculty housing area for UC/Irvine. They hope to examine interoperability and integration of various smart grid technologies in an actual full customer environment. The smart grid requires a new work force. Older workers are trained on a traditional system. This will require new work force requirements.

Edison has done several pilots, and now they are expecting to finish installing meters for about five million customers by 2012. At the height of the installations, they will have about 8,000 meters replaced every day on our system. Full implementation is on track.

For demand response, the majority has been focused on direct load control programs. There has been little price response programs. The new Smart Connect program should promote the price response aspect of demand response in the future. There is a lot more interest in the interruptible and air conditioning cycling program. In the absence of a real market, the difficult thing is providing the appropriate price for direct load control programs. This is also critical to keep costs low. The regulatory process has a lot of attention focused on getting demand response. The question really is how much do you want to pay for that demand response? We don't know that without a market. There has been an administrative processes to determine the demand response incentive.

Currently, Edison values the demand response in the absence of a transparent market price. Generally, both the prices and the variations are very small in most markets. Obviously there are very constrained times when prices could be volatile and increase significantly. One needs a capacity proxy for paying for these programs. Normally a proxy price is determined in relation to supply side resources, and the proxy used by Edison for a supply side resource is a CT [combustion turbine].

They usually devalue it or de-rate it in order to take the value or the characteristics of a demand response program into consideration a CT is available all the time. A directly controlled demand response program is not always available. It is only available 12 to 15 times a year for five to six hours a day. This issue is important for DR valuation. Many demand response programs are in day-ahead programs. They need to inform customers a day ahead that they will be curtailed. There is a difference between a "day of" option versus the "day ahead" option in pricing these programs. There are a variety of ways that Edison values their and de-rates their demand response programs compared to a CT cost, depending on the program characteristics.

Alternately, there are dynamic pricing or price response programs. The basis for most of the work in California for all three utilities for Smart Connect was a state wide pricing pilot conducted in 2003/2004. Customers were placed on critical peak pricing, and this sample of customers in a controlled pilot provided a lot of information for full rollouts later. With smart meters and dynamic pricing there was a 12% demand response during the critical peak price of 70 cents per kilowatt hour.

Despite the fact that California is starting to implement Smart Connect on a larger scale basis, there is a statutory prohibition until at least 2013/2014 to even introduce default dynamic pricing. Customers can opt out. There is a restriction against placing all residential customers on CPP [critical peak pricing], so they focus instead on a peak time rebate [PTR]. The difference between peak time rebate and CPP is, under the CPP, the customers take advantage of lower prices but they are also exposed to higher prices. Under the PTR, they bill customers on their otherwise applicable tariff, and establish a baseline usage for them. The customers get a credit if their usage falls below that baseline. It's more like an incentive without any penalty for usage during the high cost hours. If they use more during those periods, they wouldn't pay any more, but if they use less, they would receive a credit. As an economist, I always thought that customer response would be different under a CPP than a PTR. Experiments around the country have surprising elasticity's or price responses which show that PTR and CPP achieve very similar usage reductions and customer response. Ontario Hydro and BGE [Baltimore Gas & Electric] are two of the pilot programs that have shown these kind of results.

When the smart meters are implemented by Edison, they will have mandatory TOU [time of use] structure for all residential customers with default PTR. Residential customers do respond to dynamic pricing signals. Enabling technologies increase the level of response. For example, a programmable but also a communicating thermostat has been shown in pilot studies to increase response. BGE has used an "energy orb" which changes the color of the lamp when the prices are high. The level of response obviously varies by usage, household types, and whether the customer has central air conditioning or not. In addition to the similarity of results between CPP and PTR, there's been no statistically difference in response between structural winners and losers. Structural winners under a rate are the ones that have a better than average load shape – their peaks are lower and their off-peak usage is higher. When a TOU rate is introduced, they get a lower bill by doing nothing. Structural losers have a worse than average load profile. With a TOU rate they lose.

In general, residential customers are clearly more receptive to the PTR than to the CPP. Under the PTR, they are eliminating the downward risk, so that increases participation rates. Saving levels, rebates and incentives are the biggest drivers for customers in these rates. Even though customers are willing to participate in demand response programs, they really want opt-out options within the program. Edison's air condition cycling program, which has about 350,000 residential customers, turns off their air conditioner for some period of time when needed by the operator. However, the customer can override the signal from the utility if they wish, and they like that. If you place them on a rate with no opportunity to override, that is a problem. Recently the California Energy Commission was considering automatic controls for air conditioners in new homes. This cause a lot of uproar in the state. Customers also strongly respond to the idea of improving reliability and reducing brown-outs or blackouts for the state. In addition to saving money, the surveys show that it is an important reason that they participate in these programs.

Alternately, Edison puts commercial and industrial customers' on default CPP. They have a negative reaction to it. However, once Edison helps to show them the CPP can help them reduce their bills by 10% or 20%, and that it is not an all or nothing situation, they reduce their opposition. They need to be educated on why the default CPP is being implemented. They often look at the change in rates as a way for the utility to make money, they don't understand that Edison is decoupled in the CPP program. Edison makes the same amount of base revenue requirement regardless of the usage by customers. So if you explain to them why this is being implemented, it's not a money making proposition for the utility, that seems to be helpful.

Other C&I customers are reluctant to take on additional rate risk. One program that Edison implemented is to provide customers with another year of rate bill protection while they operate under CPP. This is an important educational tool. The customer works with the CPP rate for a year, and if their bill increases, then the pay under the old tariff. However, if they are able to respond to TOU then they get to keep the savings. They also like to have written information and interaction with their account representative. This can include a spreadsheet to work out the details of their usage. This allows them to work around and see if they shift their load, what kind of benefit are they going to see from these various dynamic pricing rates.

Question: What is the base price compared to the 70 cent critical peak pricing price for the statewide pricing pilot when they got the 12% demand drop?

Speaker 2: Theirs a five tier rate structure that varies by the amount of usage. On Edison's system, it starts at about 12 cents per kilowatt hour, and it goes up to 30 cents per kilowatt hour. It is a lot more than even the highest tier rate.

Question: What does the customer see, in terms of the difference between the CPP and the PTP? Conceptually, they sound very similar.

Speaker 2: It's the downside risk of CPP. In hot weather when they turn on the AC, they will be penalized. Under the PTR, that wouldn't happen. They get a credit if they go below their baseline. They only get a carrot, they don't get a stick.

Moderator: Let me add to that. I understand from the Baltimore experiment that they actually send a check back to the customer. In that case, the customer receives something in their hand that they did not expect to receive.

Question: Given that there is decoupling in California, doesn't Edison end up recovering that PTR from their customer base? Are customers really saving?

Speaker 2: Individual customers that participate are doing better than the ones that are not. There are some adjustment clauses and other balancing accounts to ensure the revenue requirement remains balanced.

Speaker 3.

I'm going to discuss the Sacramento Municipal Utility District [SMUD], a municipal utility. As munis go, SMUD is a pretty good sized utility. Compared to the big utilities in California, Southern Cal Edison and PG&E, they're only about 1/8 their size in terms of sales to the state. There is an elected board of directors that guides them and they are not under the jurisdiction of the California Public Utility Commission [CPUC]. SMUD tends to view that regulatory environment as onerous.

They have about 1.4 million people in the territory with a peak load of 3,300 megawatts. They were at a peak of about 3,000 megawatts until this particular time in 2006, when they had ten days of super hot weather, and the peak load went up by over 10% on this one event. Normally they always peak at 6:00 pm on a weekday, on the third day of a heat storm. Here they were peaking on Sunday at 1:00 and Saturday at 3:00, and it didn't really matter. They were just peaking all over. They hit a load peak that they didn't expect to hit for another 10 or 15 years. It was kind of a big deal. However, the system was pretty secure.

SMUD's approach to smart grid incorporates energy efficiency, renewables, energy storage, plug in hybrid electric vehicles, demand response, and advance metering. Sometimes you don't see energy efficiency or generation included. Ultimately, smart grid is really about total grid control, so that no matter what the conditions on your system, you can manage your grid. It will reduce the need for new power plants and transmission lines.

Let's consider what SMUD has done with demand response. In 2003-04 they conducted a power stat pilot. It was an air conditioner load management program, which they've had for over 20 years. It's a radio controlled thing. They push the button, and turn off the air conditioners. They added controllable thermostats in some homes that were controlled in the same way as the AC program. It was not new and innovative. They have 50, 67 and 100% options, meaning that the air conditioner is off 50% of the time, 67% or 100% of the time for up to four hours. If you're off for four hours on a peak hot summer day, you're really happy about the end of those four hours. The customers self select, they are not forced into any categories.

The savings almost doubled with the thermostat as compared to just the radio controlled system. About 30% of that came from attrition in the field. The radio units are on the condensing units of the air conditioners, and every time an air conditioner contractor does work, they disconnect the thing, and don't reconnect it. This meant that 30% of those units were not working. The thermostats were 2-way interactive so they could tell if the controller wasn't working. The rest of the savings came from increased participation by customers beyond the previous program.

They also had a Power Choice program that allowed customers to control a lot of different things. They used critical peak pricing, with controllable thermostats. During load periods, customers increase overall usage by 1%, but during peak periods usage declined by 16%. They created a $50 Home Depot gift card as an incentive to get customers to join the program. The customer's pretty much self selected. The customers that joined in tended to be older, better educated, and with higher incomes. Across the entire summer peak period, SMUD saved 4% of gross energy use. Customers were willing to curtail air conditioning but they were not willing to curtail computers or TVs. They reduced usage on almost every other appliance.

Another program signed up retail customers, commercial offices, and restaurants under 20 KW. Customers reduced their energy use by 20% overall and peak load by 14%. Restaurants were unable to reduce their peak load at all. They did save energy, but they could not reduce their peak load. It's a function of customers coming in during those peak periods, and they need to keep AC, ovens, and equipment running during that time. They did implement measures that saved a lot of energy. Customers had a choice of a two degree or a four degree setback. There were 78 customers in this pilot and 77 chose the four degree setback. They used programmable thermostats that are automatically set for a four degree setback. When customers are allowed to opt out, over 70% remain with the program. An opt in program results in about 20-25% of the customers who will not allow utility control of any kind in their facilities.

SMUD is now pursuing a two phase program. They developed a game with avatars like a mother and father. The goal of the game is to reduce energy in the home, but keep the family happy. It's not enough to just turn off all the lights, and the computer, and save a bunch of energy. They are offering an incentive to customers that participate based on their score. If they reduce energy and keep their family happy, they get a higher incentive. They started with 500 customers over a three day period. There are 12 parts to the game representing 12 months of the year. One might question the wisdom of using a game to develop a demand response program but it is an excellent modeling process. Based on the results they're going to implement a demand response program.

Phase two will be the field study with 200 customers. 100 customers will be a control – they will simply get a TOU rate with CPP. The other 100 will get technologies to help them reduce their usage. And I think this will be an interesting experiment to see what kind of results we get. Will the people with the rate reduce energy as much as those that have the controls? SMUD will probably implement CPP to all customers in the future but they will get extensive help with managing energy use and bills.

SMUD is doing AMI as well [advanced metering infrastructure]. It will be a full scale deployment with a 50,000 point pilot. The two extremes, dense urban areas and rural areas, are the most difficult areas to read so they are doing those first. A complete deployment will be done by 2011. They expect 52% of benefits to come from meter reading. With stimulus money for smart grid, this was one of few areas where they don't ask how many jobs are being created, because the reality is they will lay off meter readers.

In California, 85% of the state will be fully deployed by 2012 with AMI. It will facilitate different rates and TOU rates. Currently SMUD has three block rates for residential customers. A low rate for the first tier and as use increase the higher tiers have higher rates. Tier three customers subsidize tier one customers, because they're paying a lot more over time. Moving to a straight time of use rate, low tier 1 users will see a big increase in their bill, and high users will see a decrease in their bill. Their board will have to grapple with this, because they're elected by their constituents. In their current rate case, they are going to a two tiered structure, where low end customers will get a little increase. The high users a small decrease. They are doing this slowly, to move towards a TOU rate. The other option would be to have an adder or a subtracter based on usage. If you're a high user, you get a penalty. If you're a low user, you get a reduction. However, the low users are already being subsidized.

SMUD's projected energy use has a big green wedge, an energy gap, and they don't know where we're going to get that electricity. Around 2020, they're going to need electricity, and there are no plans for new power plants or anything like that. Smart grid is how they'll have to address that particular wedge.

Moderator: What is their definition of a hot day?

Speaker 3: 100 degrees Fahrenheit is a hot day, anything over 100.

Speaker 4.

I will focus on non-price influences, to challenge our thinking beyond just price. Until there is a five minute time of use mandatory rate, there will not be a perfect price. There's always going to be inefficiencies, and non-price factors can help address that. I'll focus a bit on some programs that Duke has implemented.

There are three points. First, they've been able to flatten the load without a price signal. Second, new technologies, portals and mobile devices, can promote non-price behavior. Items that focus on comfort, control, convenience, settings from work or on vacation, further depress price elasticity's. Third, there's a lot of non-regulated stakeholders people getting into smart grid options. With enough megawatt hours and the top 300-500 hours, they could become the price setters instead of a peaker plant.

The new web portals that Duke has used don't emphasize the cost bar at all. It emphasizes comfort, carbon, set my schedule, convenience. There are two pilot regions that Duke's been working in over the past two years. One incorporates solar panels and a battery. These have been going on for about two years now. The portals allow you to set modes for home, sleep, away, vacation, party, security based, turning your lights on and off when you're on vacation. As discussed earlier, making overrides possible it important for customer comfort with the program.

At this point, it's a two way program. Customers are managing the appliances. And there's this perception that it's not so bad any more. They use those two way signals to and from the utility. Sometimes it's as simple as Bob's air conditioner might come on, and the operator might punt or delay Sue's for a couple of minutes. They've achieved 9-20% reductions over a year and a half ago, and no one notices. Significant capacity savings. Further, customers sign up for it without a price incentive.

They've used opt-in, opt-out, and opt-in with phone reminders for program participation. This has resulted in 42, 94, and 50-60% participation rates respectively. The programs have resulted in leveling on transformers. It's helpful for the grid as well. If there's an average of five customers on a transformer, you need at least two participants to levelize that grid.

These programs can also address the solar intermittency problem. The operator can also dance around the clouds. Instead of load following, it's cloud following. It results in significant afternoon solar gain for a solar panel on a residential house. Dips in a graph are the clouds going over, where the solar gain goes down to zero. Normally, one can flat line the load but you don't necessarily want to do that. The big reason is minimum run times on air conditioners, or more importantly, batteries for electric vehicles, charging for one minute and then starting is probably not a good thing.

The other reason, too, is marginal cost. They care more about that than actually flattening the load. Let's extend this concept a little bit, to about five or ten years out, and the operator has about 40% smart grid customers. Consider a summer peak load day where 10% of them have electric vehicles, and they all come home at 5:00 and start charging, It's a new peak. With dynamic dispatching, the models show flattening of the load which can follow the generation plants and demand. It would require some price incentives to get some demand reduction on A/C and water heaters, so there is some comfort loss now. These models have assumptions but they show us what's possible. They create a lower levelized cost. This can pave the way for new base load that may be more efficient, whether clean coal or nuclear.

What about price elasticity? In the top 100, 200 hours, there is simply not enough elasticity on the residential side. It may well be that the price setters will be the smart grid options, if there are enough of them for enough hours. Duke has run 3 dimensional modeling on avoided costs. If smart grid demand response options kick in from 200-400 hours per year, then they become the price setter.

It would be far better to have 10-30 of these smart grid option resources. We probably don't want just 1-2 really successful options, it puts all the smart grid eggs in one basket and leaves the industry open to manipulation or gaming. Having some regulated resource in that space matters. Regulated utilities probably want to expand their activities to both sides of the meter I expect.

The other thing Duke did was try to begin to identify some of the most problematic customers. They're the inefficient, the weather sensitive, the rich, old houses; the highest cost customers. How do they know they're the most costly? When they run their loads through weather simulations and forward prices, they can clearly see the covariance effect between loads and prices ramp up during extreme weather. That covariance risk is the very reason they build peakers and have a reserve margin. The problem is that these folks are not responding to that little 70 cents or dollar or two dollars incentive. So they try to calculate the marginal cost for this guy, convert those dollars into a non-price chunk of avoided costs that they can then use in promotion or media or new technologies or new targeting specifically for those customers. They can actually figure out who is the least efficient or the most costly and target them with more promotion. Duke euphemistically will refer to them as hogs and dogs. Dogs are inefficient. Hogs just use a lot. They may not use a lot on peak. They may be flat load. Whereas dogs are inefficient. Anybody want to guess what winter dogs are? Chilly dogs? Summer dogs? [Laughter]

To sum up, price absolutely matters. But where prices are not perfect or inefficient, turn to non-price options as an alternative. In a regulated environment, either the utilities can do this, or other third parties will kick in. Even in an ISO environment they can use programs like this to lower the overall ISO price.

Question: Someone referenced Google and other third parties getting into this space. However, I've heard some argue that the utility actually owns the information. I've also heard concerns or scare tactics about security concerns if someone has access to energy information. How does this get addressed, and can it get addressed nationally, not state by state?

Second, as many players in the smart grid world seems important, because it makes everyone improve. If Google wants to come, or small new technology companies that are information aggregators and provide cool ways to inspire customers to change their usage patterns, they should be in as well. Are the real regulatory issues here, or this is a spurious debate?

Speaker 3: Right now, if someone got your usage information, it would be pretty worthless. In a real time situation, one could monitor someone's usage and determine if they're home or not, and go rip off their home. In California, the utility doesn't necessarily own the information, but legally they cannot give out information without the owner's express consent. That permission can create a huge transaction cost if you have to get consent from 100,000 customers. Companies may use some sort of online consent if they're partnering with Google or some other third party like Power Meter or ihome.

Speaker 4: This will parallel what happens in the deregulated states. It will be customer by customer, a request comes in, gets released.

Question: I've read all kinds of things about the security of the information, the smart grid goes beyond just the meter. So you hear about things from terrorism to burglary. There was actually a study, I believe it was written by somebody at one of the Southern California law schools, that talked about the potential for hacking into the databanks, and even identifying neighborhoods and identifying times of day when whole neighborhoods would be away at work, and you could get some pretty sophisticated burglars, some pretty good prizes out of this.

Speaker 1: On the other hand, the postman, the neighborhood, the outsourced customer care unit, all of that information is probably in fact more accessible today anyway. Further, these scams take a really good smart thief, and there aren't a lot of those, either.

Question: How much should we pay for demand response, particularly in the wholesale context? How does the industry reconcile that with maintaining reliability? We heard about the difference in value between generation and demand response, and another chart showed the PJM cost of new entry at $10, but the clearing price at three dollars. We heard about the energy gap that SMUD faces and that's true of the country, particularly with plant retirements coming from climate change. The last is the potential for ISO real time price signals to be gamed. How do we reconcile the interests that suppliers or demand response or utilities or regulators in demand response, yet maintain system reliability? How are those resolved?

Speaker 2: Edison looked at both the value of service and the cost based side. California still does not have a capacity market either so it's even harder. The value of service is usually determined by surveys. The problem is really just not having a transparent market. If there eventually is a market with a particular demand response at an hourly price, that could be used, but it isn't around yet.

Speaker 3: My hope is for demand response with no incentives, where the price signals are enough, and the technologies are out there that will help them reduce the loads.

Speaker 1: New England has demand resources compete side by side with generation. There have been two auctions so far in New England. In both auctions so far, the price has fallen to the floor. The first clearing price was about 450, and the second auction was like 360. In both auctions, there was increased participation of demand resources. They expect the price to fall to the floor again next week. There are over 5,000 megawatts of new resources that have qualified for the auction, and around 550 or 600 are new demand side resources. A price of around 30 a kilowatt month has not deterred participation. That's a pretty good indicator of the price sensitivity of the demand side resources, they seem to still be willing to participate at those levels. It will be interesting to see what happens as the New England market stays oversupplied in the auctions to come, or whether those low prices erode.

Moderator: Texas has 1,150 megawatts of large industrials who are paid to be available to get off, equal to their largest generator, one of the nuclear units of South Texas. Then Texas supplemented with the EILS service, emergency interruptible load service, that requires a customer to get off within ten minutes or so. The industrials thought it would be wildly expensive and would never be deployed. It's been around for about a year and a half, but the price has come down dramatically. So for a couple of hundred megawatts of EILS, they're paying around $10 million a quarter, a pretty cheap price when they look at the alternative.

Question: The rural electric co-operatives have been using demand response, particularly direct load control, for some 25 years. They're also leaders in AMI. this is because their system density is so low. They have seven consumers per line mile on average, compared with 35, 40, 50 for municipals and investor owned. The direct load control is important because they buy about a third of the power they sell at retail from the market. They use that as a market hedge. I've heard that consumers don't want to have the utility control their appliances but the coops have been doing this for 25 years with AC, dual fuel heating, and water heaters. Those are the efficient ones to control. So what is the nature of this negative response to load control?

Speaker 2: If there is a program that says your air conditioning is going to be interrupted for 4 hours and you sign up for it, that's ok. They look at the incentive. If the program is mandated by the government, you'll see unhappy consumers.

Speaker 3: SMUD has seen about 20-25% of the people that just will not participate in a direct load control program, no matter what. However, if a new cycler is put in every new home built in their service territory via opt out, the vast majority of the customers would never opt out.

Question: That's what the coops are seeing.

Speaker 4: Duke's experience has been about a 20% market share for one way load control, which is lower than the coops but it's still good. With dynamic dispatching they get another 20% bump that they projected, it's a forecast. Second, they get beyond the 50 hours critical period in a heat wave. There's a difference between the 50 hours and the 350 hours. Getting beyond 40% may be difficult for a big utility, it's a somewhat different context.

Question: San Diego will have about 1.4 million meters fully deployed by the end of 2011 and 6 million meters installed by the end of 2014. In California we've heard about the need for technological advances; a rate statute, customer education. We also heard about 50% of savings coming from the reduction in meter readers. What are the utilities doing with regard to the unions in the reduction of those meter readers, given the fact that they are substantially reducing their dues?

Speaker 2: Edison has programs that train meter readers to do other things within the company and go to other jobs in the company.

Speaker 3: Similarly, SMUD worked with the unions from the beginning. They haven't fought it "no way, no how." Generally they aggressively look to rehire meter readers in other positions. It's not clear how many will ultimately be lost, and how many will be kept.

Question: SMUD is not using a third party for installation of the AMI meters?

Speaker 3: They are using a third party that is supposed to hire the SMUD meter readers.

Question: Will entities like SMUD or Duke allow access for apps or tools to third party players similar to the iphone, where any third party can create a new smart grid app? I understand Texas is open, and third party competitors can access meters as they see fit. The competition allows a lot of diversity and customer choice in terms of what tools they can use.

Speaker 3: If SMUD is working with a vendor on some product like that, they would have to sign some sort of a non-disclosure agreement that they would not reveal that information to anybody. That's the legal concern. It may be that some of their vendors will have access to that information, but they won't be able to reveal it.

Question: Certainly vendors would create customer tools. Will SMUD control that whole process? Or will customers be able to use a third party tool if they've agreed to have their information revealed.

Speaker 3: Customers will always have the option to do what they want. But ultimately, the utility will select one or multiple vendors to provide the services that they want to. They'll maintain control. The problem right now is that there are so many products out there. There are constant vendors and multiple presentations. These days most of them have something great to add to the configuration. I'm not sure how it's all going to wash out ultimately, and how many vendors will be left standing for broad scale deployment.

Speaker 4: There will be multiple vendors in the end, and utilities will be forced to integrate with them, but also want to integrate with them.

Question: Sometimes regulators as proponents of the smart grid and smart meters are in the minority. There is a kind of a culture clash that we're facing of traditional line utility companies that are really just about keeping the poles and wires together and meeting reliability standards and staying out of trouble with the regulators. Alternately, there's Silicon Valley or the technology companies like Google, or IBM, or it's GE who are looking for a new place to sell digital technology and deploy it. The stimulus is the grease.

We charge a straight rate, say 11 cents, but it's not truly the cost of anything. Smart meters could be the first or perhaps the most honest thing we do as energy policy professionals for the consumer. Everything else has added to their cost like system benefit charges, or energy efficiency charges, or the RPS, or carbon. This allows them to manage things, and maybe actually reduce their costs.

Speaker 1: I absolutely agree. In fact we probably need to see these forces that are going to drive prices higher, to get some utilities and some states on board with smart meters. It makes a lot of policy sense to allow the end user to see their energy use in more detail and be able to react to it. Climate change policy is going to be a drive of this.

Speaker 2: Anything that can help customers keep their bills lower is important. In California the rate is much higher, but the bill is still around the national average. This is because the average customer usage in California has not increased as fast as the rest of the country; they are using less electricity. When Edison recovers that money, they turn around and give it back to the customers in terms of a lower bill. Critical to that process, and also to the smart grid is customer education.

On the other hand, all of these programs are going to add to the cost. When Edison did the business case for AMI, they included demand response and operational benefits. They also receive social benefits from carbon reduction that they would have to pay for otherwise because California has GHG limits.

Moderator: The regulators in Texas are incredibly excited about the smart grid and metering process. It allows customers to see what they're buying and when, instead of trying to remember what they were consuming 5 weeks previously. They buy no other product that way.

Texas will get killed by climate change legislation. The only tool they have to help rate payers is a smart meter to help them reduce and alter their consumption. They have a retail competitive market. The only way that works is to allow the customer to switch away from a bad retailer to another retailer as quickly as possible. With these meters, they can do that the same afternoon. Further, Texas will continue to get hit by hurricanes. The meters will allow the utilities to know who, what, where, and when a sector does not have power. The only way they know now is by people calling in or by driving around and looking.

However, there's been a more grief from legislators on this decision than previous rate cases.

Question: There's been no benefits when we spend money on all the other programs I mentioned, but regulators get grief when they want to spend $2 on a meter that will save their customers money. It's ironic.

Speaker 4: Smart meters are an important first step, especially for transparency. It's not enough. Customer still have to be proactive about paying attention. We still don't have the interactive controls and interfaces we need to make this work completely for the consumer.

Speaker 3: That's where the ORP comes in, or the LED printout above the kitchen sink, or the vocal warning that says, hey stupid, you're paying X. Those will come. When that happens, the customer's got an instantaneous feedback.

Question: How is carbon priced into the business cases associated with smart grid investments? I'm not certain that the various business cases are accounting for future carbon prices consistently. Are folks valuing carbon in the project benefits? Do regulators allow it?

Speaker 2: Edison does but that is unique to California because they will have state carbon markets soon, regardless of national legislation. Their original AMI application did not take carbon into account. It was discussed but not quantified.

Speaker 1: I've seen many business cases and not seen one that explicitly put a price on carbon. It's mentioned anecdotally. The Duke business case had scenarios in it with operational benefits, and three cases on demand response, a mid, a low and a high case. They also had 3 scenarios for energy efficiency but not carbon.

Moderator: AMI deployment in Texas did not address carbon. Their commission asked ERCOT to do an analysis of the effects of Waxman-Markey in 2012. One of the scenarios they ran was to assume that 18.5 gigawatts of wind was on the grid by 2012. Those reduced anticipated power price increases by $3 billion. Peak consumption in the middle of the summer is about 20 gigs of coal, and 40 of natural gas. If they reduce any of that fossil in the middle of the summer through smart meters, it will have an impact.

Question: Do we need more dynamic pricing in order for AMI or smart grid to deliver the benefits that everybody is so enthusiastic about? A carbon tax will flatten prices, not make them more volatile. Finally, the appliance manufacturers have the technology to put chips in appliances for smart grid, but won't do it until there's enough dynamic pricing across the country that they can justify a more expensive appliance. How do we get something that transcends states. If prices are flatter from carbon, will the benefits still accrue? Is volatility a necessary ingredient to getting the kinds of savings and changes?

Speaker 2: The demand response reflected in AMI cases mostly relates to capacity saving. There's some efficiency component in the business case, but that's not as big as the capacity component that results around the customers shifting. If there is any shift in energy use during the middle of the day, it will be helpful in terms of carbon. In these dynamic pricing analyses, when customers reduce their usage during on-peak hours, some of it rebounds during the hours immediately after that. It may not induce a lot of conservation. There is some, but not as much as the capacity reduction effect.

Speaker 4: There's two separate problems at two different levels. There's the 8760 carbon issue [i.e. the total amount of hours in a year], separate from the dynamic pricing, which is typically 200-300 hours per year. As carbon lifts price, it means plant retirements and more expensive clean coal or nuclear. That lifts the price even further. The elasticity's for the 8760 view will cause reductions. Price volatility will only get you so far. They're two separate problems with two different solutions.

Question: What do retail suppliers need, given that they're the conduit between the wholesale market and the retail load, in order to help facilitate demand response at the retail level?

Speaker 2: In the wholesale market, PJM has an auction that resulted in certain price for capacity. At $4.00 per KW or $10 per KW year, there won't be a lot of customers signing up for these retail programs. It's been more than that that has persuaded them to participate. Many retail demand response programs are emergency programs. I don't know whether that makes any difference in pricing these products than the wholesale market. In the wholesale market, there's an auction that's simple. But if the operator needs resources because they are not in balance, the customers have 10-30 minutes to respond. When you have an auction like that, and a price comes out of it, is that really the appropriate price for a demand response or interruptible program, or the air conditioning cycling program, that you push a button, and suddenly the load drops. There needs to be a lot of work in coordinating the two. These reflect two different sets of outcomes.

Speaker 3: Retailers on the residential side, and less than 100 KW, settle on averages and profiles. With smart meters, there's suddenly hourly data down at that unit, house, business level. Retailers will want settlement down at that level. It's a way to get more efficient pricing down to the customer level, as opposed to the averages or profiles they use today.

Question: What have we seen with organized or systematic programs to educate the consumers on smart grid? What was the impact, the pluses and minuses?

Speaker 2: Most programs are done on a pilot basis, and have a lot of communication with the customers. Edison is just starting with the large customers, greater than 200 KW, C&I customers who will get the rate on a default basis. They get the year of bill protection as I discussed earlier. During that year they get spreadsheets, constant contact, websites, and even if they get it wrong they are protected for the first year. That's how education is taking place for Edison. With the residential class, it will be a more significant challenge. It will start with bill inserts and have to go from there, and it will take a more intense effort.

Moderator: Texas ran pilots in each of the TDU service areas first, and they seemed to be very positive. The consumer groups were a part of that. Money has been set aside for customer education, and it's a pretty big number. The utilities are using door hangers and fliers and other communication. There will be confusion, and they will need to do more. For one thing, they are starting to see a lot of tampered meters. It's creating enormous bureaucratic and billing headaches, because the retailer may not longer be serving them.

Question: Is this the new meters or the old?

Moderator: The old meter.

Speaker 2: Another concern is that if bills are increasing for other reasons at the same time, customers will blame the price increase on their smart meter system.

Question: Please describe the similarity between the critical peak pricing and the peak time rebate. How do you deal with the double payment problem? When they reduce their consumption, and being, does the utility deduct the amount they would have paid? How does it work?

Speaker 2: Under critical peak they take the cost of a CT, and let's say it $100 per kilowatt year, and de-rate it by 60% of something like that. That gives them a 60% per kilowatt year for this program. They run the program between nine and 15 times a year, for five hours each time. This results in 60 hours of CPP. They take this $60 capacity price, divided by 60 hours that the program can be implemented. That gives a dollar amount of CPP. They take the equivalent amount of revenue and subtract it from the remaining hours rates, so that the other hour's rates are lower. The CPP hours are higher, because there are many other hours in the year. Perhaps there's a CPP rate of a dollar per kilowatt hour, but a five cent reduction in the non-CPP hours.

The customer is placed on that rate, and based on its load profile, if they use more during CPP hours, they pay a dollar per kilowatt hour. If they reduce load in the CPP hours, they don't pay the one dollar, but receive the five cent per kilowatt hour in the other hours. That's how CPP works.

With PTR, the customer is on a five tier inclining block rate, starting from about 12 cents to 30 cents per kilowatt hour. They establish a baseline for customers during the CPP hours. If the customer uses below the baseline amount during the critical hours, depending on the load reduction from that baseline, they get a dollar per kilowatt hour credit, times the kilowatt hours they reduced during those hours.

However, if they go above their baseline, they are not charged extra. They don't get penalized for using anything above the baseline amount.

Question: So the 30 cent tier that you mentioned, which is what they would have paid otherwise in this PTR case, they don't deduct that from the dollar?

Speaker 2: No, they don't. They just bill the customer.

Question: So effectively, it's 1.30.

Speaker 2: That's correct, if they are reducing usage below the baseline allowance, below the baseline.

Question: It's a little bit of an apples and oranges comparison, then. It seems to me the CPP is more effective at the same price, if it's producing the same. It's a large incentive under the PTR than it is under the CPP at the same dollar. So if the operator's getting the same quantity response, then the CPP is more effective per dollars of incentive.

Speaker 2: Yes, per dollar of incentive it is. Under PTR they are getting a benefit from not paying the actual rate as well. That's assuming the customer is participating in the fifth tier. If the customer's marginal usage is in the first tier or second tier, they pay a lot less than that.

Moderator: I've got a question for the panelists. We've heard about electric plug in vehicles but there's extensive utility infrastructure improvements needed for any real deployment. Where and how is this market progressing, especially in California? What's the likely pace of saturation? How many vehicles, in what time frame? Is this a lot more complicated than we're being led to believe?

Speaker 2: The saturation probably is going to start accelerating in the 2014/2015 time period. The deployment is going to take place in certain areas. It's the geographic characteristic that's really important, it's probably going to be affluent areas, people who are more concerned about green attributes, like Santa Monica. If there's a concentration of activity in those areas, at around 120,000 by 2012, that will be the challenge for the utilities. Currently 10 homes go on one transformer, that will be dramatically reduced if 5 of those homes have electric vehicles.

Commissioner Peevey of the California commission, bought a Mini EV, and wanted somebody from the utility to be there so he can plug in his electric vehicle and start running the next day. There will be additional issues with the meter panel, and perhaps a voltage change from 120 to 240. Utility people are modeling these impacts and trying to plan for them.

Speaker 1: Utilities are definitely concerned about this clustering effect and local distribution feeder and transformer issues. It's addressable, but a concern. The other concern, particularly with the Volt, is that it was supposed to charge at 120 volts which looks like a hair dryer to the system. Not that big a deal. Now the Volt is going to be 240 and that has a much different impact, and I'm sure a lot of the other plug in hybrids and electric vehicles will want 240 also. At 240, it's not a hair dryer, it's 1.5 central air conditioning systems; a much greater impact.

In high fuel price scenarios I've seen, with really high oil prices, the projection is that by 2030, electric vehicles and plug in hybrids could account for up to 25% of new car sales. Even at that level, the electric consumption is still only about 2% from vehicles of the total US power consumption. However, folks are going to be clamoring for faster and faster charging. The demand response and smart grid programs will be necessary to address that, mitigate that, educate consumers. Most folks don't understand that plugging in an appliance on the hottest day of the summer at 6:00 at night has some implications for the grid. Demand response programs can go a long way to education as these vehicles get integrated.

Speaker 4: The other growth area is student neighborhood areas. They want 110 volt, cheap, easy Segway scooters, or those kind of vehicles.

Moderator: The voltage matters. At 110 volts it takes hours to recharge the Volt, but at 240 it is much faster, but a bigger hit for the power company to address.

Speaker 4: If you get enough of them in a neighborhood, the transformers are not designed to go that hot that long. They're designed to cool down in the evening. If all the cars are charging the next 12 hours, the transformer can't cool down.

Speaker 2: This will require some customer education. When the customer buys a combustion engine car, they fill it up with gas and start running in. In the case of electric vehicles, they may have to ask the utility to build a month or delay expectation into their plan. It may not be reasonable to expect to plug it in regularly as soon as you've bought it.

Question: California will be relatively early in the adoption of electric vehicles, and they have seen some much higher projections, as much as 8-11% of load by 2020. If it's 10% of the load, then the timing is critical. If they charge when they want, it could add 3,800 megawatts to their peak, and change the time of the peak. If it's well controlled, it adds very little to peak and is mostly off peak charging.

Second, with the Tesla car, their fast charging version is at 480 volts and can add 19 kilowatts to the system. It only takes one of those to overload a circuit in most areas.

Moderator: Yeah, but it goes zero to 60 in three seconds. I still want it.

Speaker 1: Is that an auto company's projection of their impact? Those tend to be a lot higher than other energy experts.

Question: No, it wasn't, it's a projection from a variety of sources. It was demand driven rather than supply driven. On the supply side, there's an acceleration of the number and types of electric vehicles that are going to be available, compared to earlier projections. A lot of it will depend on whether it's full electric vehicles or plug-in hybrids which have much smaller batteries and a smaller impact. We don't know what the market is going to adopt at what rates yet. We can only make these projections and assumptions.

Question: Utilities generally have not known much about their customers. There hasn't been any real incentive, nor an incentive to be that accurate in reading a watt hour meter. What are the organizational changes needed at utilities to become smarter about the amount of information? It's going to be a thousand fold increase in data and data management. There's a cliché that Federal Express thinks that the information about where a package is, is as important as the package itself. How will utilities use that data in any meaningful way?

Speaker 2: This will be a real challenge, for sure. It is not something that they can do in a year. It's a change of culture that has to take place. The pilot programs are a start with this, and the utilities will be learning how to do it more effectively as they go. It will be a long process with many steps.

Speaker 4: It will improve over the next five years, as some of these smart grid projects roll out, and the Googles and Microsofts and the GEs come. There will be more collaboration between the utilities and those companies, and the analytics will get better. They have already improved significantly at some utilities due to increased computing power and better hiring. The process of targeting down, valuing a customer at the household level, determining where the EVs are going in, how that interfaces with solar, simulating solar or wind inputs – all those kinds of analysis are going to be the minimum for utilities in the future.

Session Three.
Siting Transmission Lines: What need of "need"?

The debate over federal preemption of siting of transmission lines conflates questions of who should decide and how to decide. The "how" may be more important than the "who." The basic paradigm has an applicant first demonstrate "need" for a new line, and then have that evaluated against the environmental and other non-economic impacts The "need' criteria are, in most jurisdictions, defined in terms of the requirements of single states or single utility systems, as opposed to broader regional markets. Benefit to native load customers is the paramount need consideration. The non-economic impacts taken into consideration are primarily local. Few, if any states, provide for consideration of broader environmental effects such as CO2 emissions. Furthermore, with few exceptions, siting approval does not provide successful applicants with the important tool of eminent domain to assure the ability to access the right-of-way and condemnation powers are afforded only to utilities.

How relevant is such a regime in the context of today's electricity industry with competitive regional (i.e. multi-state) markets, decreasing reliance on monopolies and vertically-integrated companies, increasing diversity of players in the markets, promotion of renewable resources quite distant from load centers, fully internalized reliability rules, and commonplace conflicts between local and regional interests? What is the proper definition of "need"? Can we change the paradigm for "how" without changing the *"who"? If not, what sort of regional or federal role should there be? In short, do we have a siting regime that is compatible with the realities of today's electricity market?*

Speaker 1.

I'm going to start with a brief historical review. There have been three iterations of the siting paradigm. The original was basically utility-driven where utilities did their system planning, determined the need on their own system basis and reviews were done by regulatory authorities; usually local governments or zoning boards. Utilities also had eminent domain powers which facilitated their ability to acquire needed right of way. That paradigm still exists but by the '70s and '80s began to wear down, for a variety of reasons. One is local governments began extracting higher and higher costs for siting. There are a lot of firehouses and parks financed by utility rate payers. That was, in non-polite terms, the bribe that was paid to get approvals. Transaction costs became high and it was getting more and more complicated to get facilities sited. This was a bigger concern for transmission but germane to generation as well.

There was a move in a number of states to get one-stop-shopping where you'd create a state siting agency, which in some cases was the PUC. In many states it wasn't. In Florida it's the governor's cabinet. It varies who has siting authority. 22 states still have no siting authority, it's a local function only. The siting authority would determine the need and non-economic issues, but need was determined by a system-specific or, in some cases, state-specific kind of basis. There was a tradeoff in developing that paradigm. The utilities got more streamlined processes for siting but now there was a formal participation process. Outside interveners had a much more formal opportunity to take part. In some cases, it included the ability to participate actually in the utility's own planning process.

There was also a concern that utilities might build facilities or have incentives to add to their capital base. These were facilities that might not be needed but they knew that they could recover the cost from monopoly ratepayers. The new process allowed a better look at needs so that consumers wouldn't have to pay for excess capacity. This is the model we have in the majority of states today, but not in all the states.

There are common denominators of that regime and the previous regime. First, the definition of need is parochial. It's the need of a single state or a single utility system. In a geographic and corporate sense, it is a parochial view of what need was. There is no consideration of broader market needs unless utilities coordinated with one another for reliability purposes. There is no federal role to speak of unless there's specific federal jurisdiction like federal lands or the Corp of Engineers, at least not until 2005. We'll hear from other speakers about the federal role later. The other issues is that transmission went right into native load rate base. In most cases that is retail rate based but that could include some wholesale customers as well.

Second, all the revenue responsibilities are assigned to native load ratepayers, which creates its own set of incentives, particularly in that it reinforces siting officials being parochial. If all the residual revenue requirement is imposed on a discrete set of ratepayers then siting officials have a particular reason to look out for their economic interest, and not consider broader market needs. In most cases this is in the context of vertically integrated utilities. The other common denominator is that only utilities possess eminent domain. There are one or two states where eminent domain comes out of the siting process, but that's a distinct minority.

This regime is obsolescent in the context of what's currently going on in the marketplace. There is greater reliance on bulk power markets. The siting regime is premised on a model of the industry that is no longer in existence, except the Southeast, maybe in the Northwest. For 20 years the industry has been trying to optimize the competitive nature of the industry but using a siting model that's premised on a vertically integrated monopoly model. The factors of competition are foreign to the siting process.

Development of resources distance from the load, renewables like large wind farms in the Dakotas and moving them east, or western states that want to sell wind in California. Some states view themselves as energy exporters. Wyoming, like West Virginia, was always a coal exporter, but now Wyoming views itself as a wind resource state. New Mexico is another that would like to export its resources but has a siting regime that's focused on local needs, not the ability to export.

Further, every governor in the United States is now convinced that their state is the center of the renewable universe. It is a job creation entity. It's much better to develop resources locally than anywhere else. Clearly there is less monopoly and a lot of de-verticalization, a growing diversity of players in the marketplace in both transmission and generation.

Environmentally, all siting laws look at local environmental effects like esthetics, EMF, habitat, but there's no reference to international environmental effects such as carbon. Even older issues like sulfur dioxide and other kinds of pollutants are only analyzed locally. These issues are discussed, but not incorporated in the statutes.

More recently is the specter of federal preemption, and the velvet glove in the 2005 Act. Much of the effect has largely been dissipated by a decision of the Court of Appeals. Some states have resource portfolio standards but they are not incorporated into the siting requirements.

Let's look at these issues going forward. I'll be discussing state level issues and the next speaker will focus on federal options. The siting process at the state level has two aspects. One is need, determination, and the other is environment considerations. And by environment, I mean that in the broadest sense, but basically non-economic.

Well, the original purpose for need was focused on a concern that consumers would be getting excess capacity. Utilities had to put their planning process to the test in some kind of public process and demonstrate that there was an need to build a facility. After need they had to consider the broader environmental impact of that line, which is still relevant.

One problem is the relevance and definition of need in a competitive marketplace. How do you define need where the person building it may be serving the needs of generators who aren't in rate base so the consumers only pay for what they use? There are no rate-based facilities that they have to pay for, other than the transmission itself. One could argue that need is based on reliability requirements, but reliability is at heart an economic concept. It's the value of lost load and however you choose to calculate that. In that context why is there a requirement of need anyway?

Beyond that in any case, building transmission is not easy. Nobody undertakes this lightly and they simply would not do it without economic incentive. The mere fact that one proposes a project indicates some aspect of need. There is no need for an administrative process. Reliability is an important consideration, but it's already internalized in the NERC rules that are now mandatory. Fears about excess capacity were never particularly relevant in transmission. They were always important considerations in generation debates but not in transmission.

Actually, transmission should be excluded from retail rate base. Excess capacity just simply shouldn't be a need. Transmission should be part of the FERC rate making process, not part of retail rate base. This would remove parochial siting requirements. A transmission facility should be paid for by users, not by local ratepayers, and that removes the economic incentive to be parochial.

So the first option is that states ought to remove the need requirement conduct simply an environmental review. They should also include non-local environmental impacts. Option B is to assess need in a more coherent and cohesive manner; both the in-state and the in-system needs, but also the broad economic objectives of the state and the region, including economic development but also competition and market power in the marketplace.

Obviously, one can look at whether transmission is optimal more effective load management or strategically located generation may be a better alternative. Certainly resource choices in the mix, to the extent that states have RPS and what's enabled by the building of a new transmission, is important. Does a new line facilitate RPS objectives or enhance regional environmental concerns. The kind of generation resources going into a line may or may not be relevant considerations. Those are legitimate considerations, but they're not just local.

A strong minority of states don't preempt local governments at all. Even states like Utah's exemplary siting law doesn't preempt local jurisdiction. Local jurisdictions will always have an extensive amount of input. The slight majority of states that do have a uniform siting process have sometimes argued against federal preemption, despite the fact that they went ahead and pre-empted their local government jurisdictions. Good preemption is when I get power, and bad preemption is when someone else does. [Laughter] In many cases, local governments have not be preempted. By preemption, I'm not saying local government shouldn't have input. I'm just saying they shouldn't have the final say. Anybody that wants to participate should have the input.

Another concern is that there ought to be a single uniform siting process. 22 states don't have that. Even ones that do, they may have a different process for different applicants. Wyoming has a different process for utility than non-utilities. Other states have similar kinds of things.

In some cases, non-utilities aren't even permitted to build a transmission line. There is a historical explanation for why siting was limited to utilities, because they had the open-ended obligation to serve. Today, anybody that wants to get into the transmission business is going to assume some kind of open-ended obligation to serve via FERC or NERC. Now there's no point in limiting transmission to utilities. Vertically integrated utilities have little incentive to build transmission if all it allows competitors to get into their marketplace. New entrants are critical to the market. Open access is the law but it is dependent on vigilant enforcement by FERC, who cannot actually site the lines.

Second, eminent domain should come from the siting process. If you get siting approval then eminent domain ought to come with it. Further, few developers wish to use eminent domain in any case, although it certainly helps to drive a more favorable price, the mere existence of that in the background. Wisconsin allows it, eminent domain comes out of the siting process.

Let's consider transmission in retail rate base. Consider the real life example of the Palo Verde line that SoCal Edison proposed and was going to be paid for 100% by state ratepayers in California. Arizona would bear no cost. The Arizona Commission rejected the line. They didn't want cheaper power to be exported to California, and they said so publicly. At least they were honest.

Even if they weren't worried about losing cheap power, they might have been concerned about Arizona ratepayers having to pay for the Arizona portion of the line. That would have been a more respectable argument. Why should Arizona ratepayers pay for a line that doesn't really benefit Arizona? If we eliminate that bias, and have transmission paid for by the users of the line, it eliminates the bias.

If we look at four states in the west, Colorado, Utah, New Mexico and Wyoming. They want the ability to export power into the broader market. However, these are the same states that most vehemently opposed a single geographic footprint in the west, an RTO. Now they are finding that an RTO would have served their interest and provided an effective environment to address regional needs, and to allow them to make the case for building transmission that will allow them to export their new wind.

Question: How does cost recovery work if transmission is not in rate base?

Speaker 1: The question is *which* ratepayers pay for it and whether the cost of distributing is proportional to the use of the line. In the Palo Verde line, the costs would be borne by the APS customers only. Now, to the extent that So Cal used the line, revenues would be produced, and presumably they would go back to offset the revenue responsibilities imposed on Arizona ratepayers. But that's subject to a lot of vicissitudes about the timing of rate cases, and other details. I'm saying that if 100% of the benefit went to So Cal Edison's customers then they should bear 100% of the cost. The user would pay and FERC would set the rates.

For utilities somebody is going to assume the responsibility for their revenue requirement, from a price signal standpoint, it's the most efficient way to do it. From a siting standpoint, it allows siting officials to get away from being parochial.

Question: Are you saying it should go into Southern California Edison's rate base?

Speaker 1: No, it would go into whatever FERC used to set the rates.

Question: But FERC doesn't set retail rates.

Speaker 1: No, the states would have to pass it through. The costs get passed through to the ratepayers that use them.

Question: You're saying we shouldn't automatically socialize cost across rate bases. It should go to those who cause the cost to be incurred, is that what you're saying?

Speaker 1: Well, its beneficiary pays. Actually, it's the actual user pays. Those that actually use the facility ought to pay. It stops a bad incentive from going to state siting officials.

Question: Pancaking means different things to different people. What does it mean to you?

Speaker 1: I want to avoid a transmission company not to have to pay multiple transmission tariffs every time they cross somebody's territory in multi-state situations.

Question: One concern is the cost of capital. Transmission is very capital intensive and, if it's not in the rate base, it costs a lot more to get capital from Wall Street. Have you accounted for this?

Speaker 1: I've focused only on siting. It's a different issue that should probably be addressed at some point.

Speaker 2.

I will focus on federal issues in siting. One can visualize the jurisdictional issue at the lowest levels all the way up to the federal government. Siting models started with the investor owned utility model driving siting within a single jurisdiction. The local and state models are a stable regulatory approach for dealing with those kinds of issues. But as wholesale markets have evolved, and new attention to climate change and renewable resources have evolved, these historical jurisdictional lines have been pushed to evolve in certain ways. I'll focus on the extent that the federal government should step in and override state authorities.

Let me start with the dormant commerce clause. This can be used, under the federal constitution, to preempt the most egregiously parochial state siting decisions if they are discriminating against out-of-state producers. If regulatory authorities make blatant statements that appear to be protectionist to the press then this approach can be prosecuted, but there has been very little successful application of that doctrine in this context.

Instead, I'll focus on themes related to federal statutory preemption. First, I want to highlight the much maligned Piedmont case. FERC has some tools that could be used to address instances of parochialism. Second, I want to discuss some of the pending legislation. There is this sense that FERC's tools may not be adequate and that they need stronger powers in new federal legislation. One bill has passed the House of Representatives and there's a senate bill that's passed the Senate Natural Resources Committee. The house bill has some good things but presents a curious distinction between federal backstop authority in the Western but not the Eastern states. Further, even if the house bill or the senate bill were to pass, neither those, nor existing FERC authority sufficiently addresses this issue of cost allocation that was just discussed.

Let's start with federal authority. Section 216 of the Federal Power Act added in 2005 gives FERC backstop authority in the national interest electric transmission corridors. This was to address transmission reliability and the expansion of the wholesale market, not to address broader issues of climate change or the development of the renewable market.

There are explicit circumstances in which FERC has preemption authority. First, if a state does not have authority to approve the siting of facilities or if it cannot consider interstate benefits then FERC can preempt. Second, if a non-utility cannot gain siting approval because it's not a utility, then FERC can preempt for national interest electric transmission corridors. Third, if a state commission has withheld approval for more than one year or has conditioned its approval so the construction will not reduce transmission congestion or becomes economically infeasible, then FERC can override. However, in this case, the Piedmont ruling by the Fourth Circuit reversed FERC's interpretation concerning the clause, saying it only applied to denials, not inaction. That ruling is under appeal to the Supreme Court by the Edison Electric Institute, so we will see.

Further, the national interest electric transmission corridors are extremely limited in their geographic reach. They were defined by the Department of Energy in 2007. They don't extend to areas of the Rockies, parts of Texas, or other states that might potentially have robust natural resources. The Obama Administration, reflected in the testimony of FERC Chairman John Wellinghoff, has made it clear they would like to expand this approach. "We need a national policy commitment to develop the extra high voltage transmission infrastructure to bring renewable energy from remote areas where it's produced to most efficiently serve larger metropolitan areas where most of the nation's power is consumed." That's the starting point for a lot of the pending legislation that addresses transmission siting.

The house bill is the Waxman-Markey bill, HR2454. It overrules the Fourth Circuit's Piedmont decision by authorizing FERC to issue certificates of publics convenience and necessity, not only when the state commission delays action but also when it denies an application outright. However, it expands FERC's jurisdiction beyond national interest electric transmission corridors to cover the entire US portion of the Western interconnection. It's not clear why the west is expanded but not the east. In testimony before the house, Eastern states, including Massachusetts, voiced concern that federal backstop authority could disrupt offshore wind developments by authorizing transmission projects to bring in energy from the west that would be cheaper. Others note that the East is largely built out unlike the West.

The political influence of energy exporting states rich in renewable resources in the west have been seeking regional coordination. Given that the west has no existing strong RTO model, this may function as an alternate approach for transmission coordination. Waxman-Markey does other interesting things. It proposes regional planning entities for transmission with FERC review of these plans. The principles for planning are fairly broad. They include the consideration of carbon impacts on a broader scale than just a state-by-state or regional perspective. There are national climate change goals that are considered. In addition, it can take into account all demand side and supply side options, including energy efficiency, distributed generation, smart grid technologies, and electric authority. FERC is mandated to establish grid planning principles from these policies within one year.

The Bingaman bill is now dominant in the senate and passed his committee this summer. This is the American Clean Energy Leadership Act of 2009. And it gives states a year from the time of filing a proposal to site a high priority national transmission project, and it gives FERC broader jurisdiction than the house bill does over siting when states have been unable to site a facility or have denied the application. There's no distinction between the west and the east.

The big issue in S1462 is cost allocation, which the bill provides for. The house bill is pretty silent on the issue. The senate bill addresses it, but an amendment added by Senator Bob Corker from Tennessee prevents FERC from spreading the cost of new transmission broadly across multi-state regions unless the commission can justify it by showing specific economic and grid reliability benefits. The language requires that the cost be reasonably proportionate to the economic and reliability benefits of the line. This language has caused alarm at FERC. They are concerned that this may lead to prolonged litigation.

Now, to conclude, let's examine what's not addressed or resolved in the pending bills. First, there's no clear sense that the factors in siting decisions will be focused on the national market or climate change goals. They rely heavily on regional planning entities or retain a role for states. There is no clear sense parochial state processes will be overwritten and the narrow state concerns won't carry the day in significant parts of the country. Second, the transmission cost allocation issue isn't completely resolved. The house bill is silent and the Senate bill has the concern for proportionality. Finally, the governance role of RTOs and other regional bodies remains uncertain.

So I'm back to my three themes. The first, FERC has existing tools that can be used theoretically again, right? DOE may need to do a new rulemaking, and reclassify transmission corridors to include other parts of the country. There is some indication of a cabinet level unified strategy that FERC, Department of Interior and DOE are pursuing for corridors.

Second, if congress does act both of the existing proposals present imperfect solutions. The house proposal has the strange distinction between east and west, and doesn't address cost allocation. Third, the Senate bill is limited with cost allocation and may simply mire FERC in litigation.

Speaker 3.

I have a different take on some of these issues and will discuss them from the perspective of the east coast to some degree. We need to define our problem. I'm not sure transmission siting is the core of the solution to get us to the right energy future. It may not even be part of the critical path

There's a very consistent perspective that we need a superhighway, we need 965 kV lines running everywhere, and we need to move on it now. There is an appeal to this, but it's not necessarily going to be in our best economic interest. Over the last dozen years or so, our spending levels for transmission have been going up dramatically. We're now approaching a little over $10 billion a year on spending. It's five times the amounts from ten years ago. There clearly seem to be effective mechanisms to get transmission projects sited and built and funded in existing regulations and legislation. They're getting a lot of it done.

Some say our grid is a Third World grid and hasn't been upgraded in 50 years. That is clearly wrong. Our electricity supply is extremely reliable. It is the envy of the world. The system operators are completely different, even over the last 20 years. The operators are doing an amazing job that we often don't see.

Thus the core question is what is the utility of transmission? It has no inherent utility. It simply is an enabler of outcomes. We need reliable power. We need to reduce our electricity costs. We need to reduce our carbon emissions. Transmission is part of that solution. Those issues need to be the focus.

Further, there are gigantic challenges in transmission: in siting, who pays for it, the disruptions of local folks, states and so forth. There are questions of who benefits and who's in charge from a FERC standpoint, a state standpoint and local.

The six states in New England are looking for the best solutions across the region. They're open to whatever brings the best economic answer for their end-user customers. It's not clear that transmission builds will do that. In particular we've seen where the wind potential is and the load centers and envision a transportation system for it all. The concern is who is going to pay for it, and how it gets done. They are big plans with 765 Kv lines all over the place. AEP has a plan that looks like the spread of a virus. It would be tens or hundreds of billions of dollars of opportunity for one utility. It is akin to the build-out the rail system a hundred years ago or in broadband 15 years ago.

There are other ways of dealing with renewable development. The Massachusetts Renewable Portfolio Standard [RPS] originated in 2003. In the early years they allowed early action, and so some entities could bank renewables. In subsequent years, significant alternative compliance payments were made because there simply weren't enough renewables being developed. However, in 2008 and 2009, they're now in surplus again. They are developing a significant amount of renewables, both in the region and in the neighboring electric systems. They've had to drop the renewables energy credit pricing down by 50%. It's gone from $60 to $30 a megawatt hour.

Their RPS is stimulating the market, and created new projects for a greener future. They now have about 14% renewables, about 5% is counted in these new renewables, part of the

RPS, and then about 8% or 9% is traditional. They aren't part of the RPS, like existing hydro and other resources. The emphasis is on creating renewables locally. ISO New England data shows that the growth levels are similar across the New England region and are strongly forecasted well into 2014.

On the other side of the equation, there's been a strong focus on developing demand response resources. The focus of companies like EnerNOC and others is about reducing peak demand. In 2007, in the East Mass region, 88 hours a year accounted for 15% of the peak capacity. Demand response has been an enormous piece of addressing that component of the market. It is now a very reliable contributor akin to the traditional generation resources to be able to meet the demand of the system and be able to dispatched reliably. Again, market solutions are addressing the issues in the region.

About 85% of the time prices are within 5c and 10c per Kw and that isn't going to change a lot of customer behaviors. The other hours are too few to make a big difference. So while Smart Grid and an improved transmission system is important, it should not be one size fits all. We're hearing about a gigantic hammer here, it's called transmission, and the feds want to pound down all the nails they can with it.

The focus in Massachusetts has been entirely about environmental and economic benefits and finding the lowest cost solutions to get there. This is being done within the portfolio of resources they have available. It's just not clear that transmission is a cost effective way to do that.

If green energy suppliers can bring in green power that is cheaper than the alternative, including the cost of these huge transmission projects, then the New England states would welcome it. Costs in New England are very high, especially in Massachusetts which is fourth in the nation. Cost effective renewables make better sense in Mass. than just about anywhere but with these huge transmission projects, it may not be cost effective. Massachusetts has a high ability to generate gross state product from the BTUs that they consume. They are a relatively energy efficient economy.

Finally, energy efficiency is a big priority. National Grid, one of the utilities in Massachusetts has had 30 years of continuous energy efficiency and demand side management programs. Their various programs each have 10-15 year lives, and over time 8% of their energy demand is now being avoided because of these programs. Programs that are just starting will be that much more aggressive.

There are lots of policy levers for pursuing a more economic and greener future. Transmission is part of the solution, but not the critical path. That's why Waxman-Markey understood that a one-size-fits-all transmission solution was not appropriate. States have a critical role in making this transition successful. Regions are working collaboratively and market solutions are driving success towards these goals.

Question: What percentage of high prices for Massachusetts is due to congestion on the system?

Speaker 3: It's a concern, particularly the Cape and the Southeast Mass area, but not across the state very much. They're at the end of the pipeline for all resources so 85% of the time their wholesale price is being set by natural gas. There's still high divestiture charges from the past.

Speaker 4.

I'm going to use the Wizard of Oz as theme today. However, there is not a yellow brick road. I'll focus extensively on the Mountain West states and on New Mexico in particular.

There are four critical questions. First, northeasterners may think having that national grid is impossible and perhaps undesirable because of wanting to develop your own resources. For a New Mexican or a Texan it's not difficult at all. They have California there and they don't want to build things. They have a BANANA attitude, build absolutely nothing anywhere near anything. If you look ahead to 2050, I think we have no more coal. Do we need a regulatory regime change? The Emerald City is green. We need to continue to focus on enhancing renewable energy. We can't do that and keep cost down.

In the west the transmission constraints are tremendous. We have one New Mexico utility that issued an RFP for renewable power and now cannot meet its renewable portfolio standard, 15% by 2010, because they can't get transmission to bring it in soon enough.

Another concern is transmission of fossil fuel from renewable producing states to other states through displacement. Consider a producer of solar power towers in the west, but major fossil resources come from there too. They have coal, gas, wind, and solar. The wind in the Mountain west even blows around the same times as the peaks.

It can be possible to provide renewables in New Mexico, export the fossil resources, and prevent the inhibition of renewables in states like Massachusetts that are trying to develop them. It needs to be carefully controlled and coordinated. The vertically integrated utility is a disaster for encouraging transmission or utilities. The prime directive is to make money for their shareholders and they usually did it by selling their own generation across their own transmission, especially in the west.

Divestiture is ultimately not relevant. If there is a corporate family in the minds of the people who are running the affiliates, be it transmission and generation, they're thinking about how the whole gang is going to make money. They have superior knowledge. There's transfer of key employees between the companies. All above board, and within FERC requirements but it happens naturally.

The best solution is to encourage third-party transmission development, similar to independent generation. Hopefully they won't have the same problems as generators did with their wave of late 90s bankruptcies. The Scarecrow, the Tin Man and the Lion are the Transcos.

New Mexico has a significant development within energy. They have a FERC commissioner, Senator Bingaman, etc, and some very progressive legislation and regulatory regime. They allow non-utility construction. They've expanded the eminent domain powers through an agency called New Mexico Renewable Energy Transmission Authority. They have improved cost recovery and financing. Cost allocation issues have historical been handled

They have state bonding authority through the New Mexico Renewable Energy Transmission Authority. We call it RETA. They don't have region-wide rate setting. Parochial state regulation is still an issue there.

There is a significant concern for tribal sovereignty. The Four Corners area, Utah, Colorado, New Mexico, Arizona has a reservation that is the size of West Virginia. It's located right near the coal reserves, right near the plants and you cannot get the power across. The cultural perspective on preservation of sacred sites to the Native Americans cannot be simply solved with money. Or you need exorbitant amounts.

Multi-agency siting decisions are a concern also. New Mexico has a single siting authority in the public regulation commission. It's a simplified approval process and they preempt local governments depending on what the size of the lines are. They really need expert environmental decisions though. They have minimal experience with these concerns and it has caused ongoing problems.

Much of the perspective is local, not regional. The west is really balkanized in the truest sense of the word. Pancaked rates have been an issue since the beginning of the Western Electricity Coordinating Council, and it is still unsolved. However, an RTO is not the answer either.

In New Mexico, they have very expansive definitions of need and public interest. The Commission can consider carbon footprint, regional benefits, New Mexico economic development. It's an important control over construction of transmission.

We've heard through the day that reliability really is the value of lost load. However reliability is more than that. The intangible political value of reliability is tremendous. It's an elected commission in New Mexico so it's voters, not consumers. They don't want a monetary value on loss of power, on brownouts and blackouts and such. It's arguably worth more than that for them. National energy security and climate change are components of the reliability consideration because it is so political.

While New Mexico has superb resources, and a renewable energy transmission authority with eminent domain power and bonding capacity. Unfortunately, it hasn't got any resources so it doesn't do anything. They're trying to launch some projects, but in two years they have not launched one. They haven't had a line built since the 1980s.

What is the ruby slipper for New Mexico and the west? It requires a sea change. It's about regional solutions, and money issues. The certainty of recovery and the ability of third-party transmission providers to obtain financing is absolutely critical in this economy. Otherwise people cannot get financing.

It's OK to revisit Western RTOs as called for in Waxman-Markey. I prefer the senate bill because it provides just backstop authority. The backlash from the RTO-ISO wars of the earlier part of this decade will be a bigger obstacle for that battle, and it may not be worth the fight. There is an alternative to RTOs or imposed regional regulation. Simply expand the national transmission corridors. The alternative is collaborative regional regulation. They are actually experimenting with that in the Northwest with a group called the Northwest Tier Transmission Group. Their motto is don't prejudge, prethink. One of the big legal issues are commerce clause versus compact clause which says any agreement between states requires Congressional approval. If you don't go to Congress, the NTDG is discussing presumptive need. The regional collaborative process, the planning, siting and cost recovery is recommended and creates a presumption of need for each commission because of the collaboration. The creation of a presumption is a very big help in moving through the regulatory process.

The answer here I think is a form of regional self-regulation that incorporates all the facets I've discussed. If it doesn't work, federal preemption perhaps would be the solution.

Moderator: I have some questions to start. Cost allocation, who's paying for this line, is almost the threshold question. It and siting are interlinked. How we define need is critical. It is expansive in some places like New Mexico and far less so in others.

Second, transmission goes through multiple communities, unlike generation. There are multiple concerns in every one. Firehouses have to be bought in every one. If we are really going to talk about federal preemption for siting and the big crayon map of 765 Kv lines, what is the firehouse that the feds are going to offer to all of those states in between? When you site something, there's financial support in return.

Question: In California, need is based on either reliability or economics. Now there's a new paradigm. With a renewable portfolio standard, is it a constrained economic need? They're looking for an economic need for transmission given that they have to meet some renewable portfolio standard. The problem with that paradigm is that it's really too complex to implement. They're saying this transmission line is needed because it's better than any other alternative. Well, that's a difficult test to meet. The California ISO is looking at this need based on reaching out to renewables. Can we define this? What about need based on siting renewables but also open access for traditional generation?

Speaker 1: That's why they should get rid of the determination entirely. The political capital used up to get a line sited is phenomenal, not to mention how much it's going to cost. Need is mischievous. It was useful in the past. There's no longer a concern that we're building excess capacity.

Meeting RPS goals can be one of those needs, but a single purpose need is just too much mischief. It should be eliminated.

Speaker 2: Another aspect of the renewable market that complicates things with renewable portfolio standards is the role of renewable energy credits in assessing need. It's not a direct allocation. There might be some sort of financial transaction that's occurring, perhaps in a different more remote state, so the physical electrons aren't even necessarily coming into a state if they move to a national renewable energy market.

Speaker 4: My concern with eliminating need is another movie analogy from Field of Dreams, which is build it and they will come. We've seen many generation facilities built that way, and they are in excess. We do need some regulatory oversight, also a forum and way for localities and people in the communities to raise issues. We probably do need a need determination but it should be very broad, including reliability and, long-term national energy security.

Question: One path forward would be holding utility procurements based on load centers in Southern California, San Francisco, whatever. Put out an RFP for a thousand megawatts run by Cal ISO, the PUC, or the CEC. It would be a ten or fifteen year contract. The winner provides the cheapest delivered cost of electricity, or green electricity into the market. That would crystallize the competitive environment. It could be mixed up too, some local, some not, bigger or smaller. I'm still curious, without need how does the payment get allocated?

Speaker 1: The people that use it ought to pay for it. It's a beneficiary pays system that can be adjusted over time. Arbitrary assignment into a utility's rate base doesn't reflect that.

Question: Is it a merchant transmission model that you would support?

Speaker 1: I like the merchant transmission model. Ultimately, I like what the Brazilians do, which is they identify a need and they go after a bid. The lowest developer who wants the least money builds it. That's another model.

Speaker 2: There's another important consequence of finding a need. It creates a presumption in a later rate case that the project will be included in rate base, and the commission tends to follow that. So, it leads to that arbitrary decision to include it in rate base.

Question: Nobody talked about the cost of the transmission investments themselves. They are consistently over budget. There is no discipline in the projects. Further, some companies may be able to make more if the costs increase.

Speaker 1: I have looked to see if there had ever been cost disallowed for transmission by any regulator anywhere. There is one example about 25 years ago in California, but the PUC reversed itself in the rehearing. This is in large part because it's ultimately such a small part of the overall cost. Presumably a regulator could review the prudence of the cost but this is clearly unlikely. Part of the problem is the bribes you have drop along the way in order to get the line built, the park, the firehouse, whatever else you're doing. Some of those things don't get anticipated. How does one view those kinds of bribes? Are they prudent bribes or not? I mean who knows? [Laughter]

Speaker 2: I have observed the same phenomenon. The costs get extensive scrutiny beforehand and then it ends entirely. Then whatever it ends up costing it ends up costing and goes into rate base be it federal or state. I don't have a good solution for that. Moving more towards a merchant structure with a delivered cost or a contract that defines how much revenue they're going to get from it might be mechanisms to deal with it, but it's a difficult challenge.

Speaker 1: In the Brazilian model, they bid on the project. If the developer wants to build it, they bid to build it and the bid is what is recovered. That is a very upfront way of doing prudence. If they run into unanticipated costs, it's their problem as the investor.

Speaker 4: Regulator's see the hundred basis point adder for investment as a perverse incentive. One could ladder the incentive based on performance to cost.

Speaker 4: In New Mexico during the need determination for building a plant, the utility has to provide the estimated cost. During the CCN [cert. of convenience and need] case they determine what's going to go into rate base. New Mexico has a very settlement-oriented regulatory model. To get the CCN the company has to agree in negotiations not to ask for more than X amount more than the estimate, and they bear the increased cost risk. This is also a reason I don't agree with separating siting from need and cost. All three things should be looked at together because I think they are so inextricably related that you can actually more efficiency determine when, where and the cost of transmission line. They do this in New Mexico as far as plants go but not transmission, and I'm not sure if the statutes apply to it.

Question: I'm nervous when congress is writing legislation and they get very specific in what they're constraining or setting as the goals and objectives. We heard that the description in the senate bill about cost allocation was defective in some way. In particular, this proportional to benefits and beneficiaries. What's wrong with it, and what is the better prescription?

Speaker 2: I would prefer giving regulators the discretion to define some of those parameters. The legislation requires that FERC, before regionalizing and spreading costs, determines the costs are reasonably proportionate to economic and reliability benefits. It's a clear cost benefit sort of test. However, reliability hasn't been defined in this context, and this vague concept can be used to constrain the agency, if not tie the agency up in litigation for years. Reliability concerns could include diversification of fuel source, for purposes of climate change, energy dependence and the like, or reliability that is purely physical or engineering oriented.

Ultimately, I would leave it even more open and make it clear that the agency has discretion, like they do with just and reasonable rates.

Question: I want to address transmission investment and separating it for reliability versus for economic or renewable needs. We heard that transmission investment is increasing over time, but those investments are mostly for reliability needs or replacing aging infrastructure. Those are easy, and the process is clear. However, now they have to fold in the environmental and renewables aspect and they are completely new. It is hard for policymakers and planners and utilities to tease out the reliability effects of transmission upgrades from economic and renewable effects as well.

The utilities in the New York ISO are working on a study that will encompass more than just reliability into the study. They are trying to simultaneously assess all those needs together, and it's not clear it will work. Can one effectively separate out reliability needs from economic and renewable needs and be able to actually wrap our policies around that?

Speaker 1: No. The distinction is absolutely meaningless between reliability and economics and renewables for that matter. It's a question of the degree of economic necessity more than anything. Reliability is presumably a greater economic need because it is the value of lost load. Some regulators have viewed it as reliability meant a utility wanted something for itself, economic meant it was for somebody else's benefit.

Speaker 3: In New England they have to do this from a cost allocation standpoint. A model that is more merchant or even Brazilian would make it much easier to do on a contract-by-contract basis instead of trying to forecast all of this potential construction.

Question: The merchant model could work for radio connections or inter connector ties. However, merchant models don't work for upgrades that are based on existing rights of way; that gets very complicated.

Speaker 1: There are a variety of issues there. First off, for siting purposes, many upgrades don't need approval so the siting problem goes away. It gets addressed through traditional rate-making. New rights of way are a different issue. The optimal economic choice is a regional planning concern. For siting, there's a set of decisions, whether one builds the line is a separate decision. There may be a variety of other things that are a lot more efficient to do.

Speaker 2: I heard your question as a cost allocation question. FERC has taken very different approaches to cost allocation depending on the proposal it's considered. In June it approved two different approaches, the New York ISO approach, which is a governance model. Basically, unless 80% of the ISO's customers agree, the transmission costs are not accepted or regionalized. The same month it approved the Southwest power pool cost allocation model which used a very different approach. It is a substantive economic model for allocating cost, allocating 67% of cost upgrades for wind and regionalizing those within the power pool. These are very different approaches depending on the particular power pool or ISO that's making a proposal. There is no consistent model.

Speaker 4: In some instances, you can isolate the cost and determine who's benefiting and not socialize them. If you cannot do that, then expand the definition of reliability and just socialize the cost. If we really want to have an impact on climate change and a new future, we have to pay the costs. It's socialization when you have to and allocation when you can.

Question: We've heard that a need determination is moot. Transmission companies will build merchant and get paid, or have a project put into rate base. If it goes into rate base, how can you not determine there's a need for it if the ratepayers are on the hook?

Speaker 1: For purposes of *siting* you shouldn't have a need determination. I presume there's going to be some regional planning process, particularly in organized markets, about whether the project gets built. There is a need determination made economically in the regional planning process, which includes reliability, at that point but it should not be part of the siting process.

Question: A utility is not going to build it unless they know they can recover it. If they know they can recover it in some way they have every incentive to build it. Somebody has to make a need determination. If we're suggesting that that's the RTO's job for some reason, that's another discussion. It's not clear everybody would agree that they're qualified to pick between three developers who want to build a line.

Speaker 1: In theory, there's an organized planning process in an organized market. There's a planning process and a determination that it's going to go ahead. In the absence of organized markets that is a real problem. Determining the need by a siting agency doesn't necessarily guaranty recovery either. The original concern was to ensure they didn't build excess capacity. At this point we do not need to worry about that. It's not a problem.

Question: There's a debate about a federal siting authority but there's a very successful model operating at FERC. It's the gas pipeline siting. They used to do a finding of need. It basically consisted of people fudging reserve bases and demand forecasts which, after the line was built, turned out to be wrong and people apologized. Then they socialized the cost. In a sense, they rolled them into all the customer's rates.

In the '90s, they dropped the need, they used participant funding and/or beneficiaries pays. You come with your own money, you play with your own money. The process and the contention dropped an order of magnitude, and it seems to work very well. Now there is only an environmental review where they look at alternatives and things of that nature. The improved significantly. I believe FERC does a need finding, but it's essentially saying, well, there's a lot of money going after this project so somebody thinks it's needed. The problem is using rate base. The beneficiaries pay model or the participant funding model is faster, better, more equitable, and less contentious.

Speaker 1: Well, when local rate base is combined with a need determination you really force the siting agencies to be parochial. In order to protect their own consumers they have to be legitimately parochial, and that's the wrong incentive to give them.

Speaker 2: The Southwest power pool proposal has a balanced portfolio approach where all of the states agree on the funding before the process, before the construction goes forward. This is a significant difference. Some people believe that this was a fool's errand, but, in fact, SPP has gotten unanimous agreement on several occasions to build lines.

Question: I want to clarify the federal versus state jurisdiction in cost recovery. In California, the utility proposes a line whether it is for reliability or economic purposes. Then the independent system operator has to approve that line. Then they go to FERC for rate approval. FERC is the one that even sets retail transmission rates. It seem that the state really has a limited role in determining what goes into rate base and what is prudent.

The concern I have with the user's model is that if you make a substantial investment in a transmission line, and you build it and they don't come, I don't know exactly how you'd recover your revenue requirement. Under the use model it will require a much higher cost of capital to make that investment.

Speaker 1: That's true. However, most states don't go to FERC for rate approval, California is unique.

Speaker 2: To the extent it's in retail rate base, and this goes back to the need question again, if need is a presumptive prudence determination that doesn't necessarily do anything to control cost at the front end, that could offset any sort of benefit in terms of the cost of capital.

Question: Let's examine this distinction between reliability and economic and green transmission. I don't agree that utilities use reliability as a way to get projects in. In PJM the RTO identifies the need first, and they use very clear NERC planning criteria. There are often economic benefits as well as reliability, certainly in several of the PJM lines. Regulated transmission, at least in PJM, is not competing with generation or demand response. Generation, demand response, and efficiency are the first choice.

Merchant transmission always has the first opportunity. It is active in New Jersey and New York City. After that, and all the other things, then transmission gets built from a reliability standpoint. PJM also has a separate economic transmission planning process, which looks at congestion in a very defined way. There has been only one transmission line that has satisfied that test because transmission is extremely expensive. It was a tiny $250,000 transmission project.

Finally, there's the new category of green transmission, but we can't identify between green and brown electrons. There is this crayon approach that assumes we need a tremendous amount of transmission to deliver renewables. However, we don't yet have a national policy on carbon, a price, or a national renewable portfolio standard. We're putting the cart before the horse. Further, the wind and solar doesn't necessarily need to be delivered all over the country, it can be traded via credits. The air is being affected no matter where it's located and the carbon benefits will be achieved regardless of where the green power is used. It doesn't need to be deliverable. Can you address these various issues?

Speaker 1: Let me discuss utility's use of reliability. First, you've made the case quite eloquently for organized markets because they've dissipated a lot of that cynicism. On the other hand, from the 80s to the present, we still hear from utilities that certain reliability projects are critical. American Electric Power had presentations in the 80s in Ohio with electrons with white hats and black hats. The white hats were AEP projects and the black hats were independent. In June of this year, the ICT [Independent Coordinator of Transmission], the pseudo RTO in the Entergy territory, indicated there were 20 specific upgrades that had to be made. Entergy said you only need ten, which apparently just happened to be located near Entergy's plants and not near any IPPs. I'm sure that was coincidental. The reason for the cynicism exists and organized markets address it to a large degree.

This all rolls into this question of economic need and trying to determine who benefits. However this can be determined by the nodal price, which reflects how the costs should be distributed.

The question of putting the cart before the horse is an interesting one. I have focused here on how to decide these questions and what is the appropriate form, process, and criteria for deciding these questions. I don't assume that we need a green transmission highway. The question I'm trying to decide here is how we go through the process. Congress is clearly going in several different directions when we really need to develop an institutional mechanism for making these kinds of decisions. Congress needs to set the basic policy but then create a framework for setting out all the subsidiary policies that need to follow-up on that.

Speaker 2: The focus should not be on utilities as good or bad guys, but on the decision-making process, and moving beyond a local and state-wide process to consideration of broader and regional issues. The approach I've discussed solves this problem: assume PJM decides a transmission lines is economic or reliable, but the state of New Jersey refuses to site it. We need a process to move beyond that.

Question: That is a legitimate issue and that is exactly why we need federal backstop siting at a minimum, because the local siting process is clearly inconsistent with regional planning. I'm just concerned that part of this process seems to allow for us to build for whatever seems to be appropriate at the moment and get out ahead of congress and the national view.

Speaker 4: Another concern is the availability of cash in a utility. If you have a cash strapped utility they are not going to enhance or build the transmission system for a third-party, they're going to spend their money doing something else. If there is a utility that has cash that it needs to invest that's a really good idea if they have enough generation to build transmission for other merchants and renewable merchants.

On the cart before the horse issue, I'm an advocate of the crayon map. The majority of renewable development is rural, they don't have large load, at least in the west. And I would think so in the east, too. For example, Rhode Island with lots of offshore wind. In order to get RECs to buy you have to transmit that power to some end-user somewhere, and have it displace fossil. Utilities are not going to want to displace fossil, they're going to want to recover costs on fossil and maintain that system.

Question: The PJM process has addressed the first issue that you've raised; it's a very good process. The transmission owners have an obligation to build whatever PJM determines is needed for reliability. That's not the case for economics, and that's gone to FERC. If the transmission owner is not interested in building because of capital needs or other reasons, then another transmission owner in PJM can pick up that obligation. That's happened with the Susquehanna Roseland line, it's being built by PSEG over several service territories.

On the second point, clearly integration of renewables may become a reliability issue that needs to be addressed through transmission. Backstop regional planning will have to fix that. However, we have generator interconnections and FERC's very creative approach to anchor tenant models and financing mechanisms, coupled with backstop transmission planning. This, in conjunction with regional processes probably will work well.

Question: First, a side note. There are significant differences between the west and east. The number one barrier to siting in the west is federal lands.

Second, it is a presumption to have a need process in a traditionally regulated state. It gives utilities a presumption for guaranteed rate recovery and reduces financial risk. Currently there is no momentum for change in the west in terms of organized markets. Can some of these proposals work in a traditionally regulated system? Some of the suggestions increase the risk to utilities and may make the lines too risky to get built.

Speaker 1: I don't think there's a single answer because there are so many differences. For example, in Utah, they're part of PacifiCorp which is eight states. They have a fairly long history of cost allocation and working those things out on a multi-state basis. In other places there's single state utilities and it may not work as well. If you're an energy-producing state like Wyoming then you want to see a broader market. How can they do it if your neighboring state wants to block that and how will you work together? Moving to a regional approach sets the stage for addressing these questions. People are going to do what they need to do to keep the lights on. The question is what is the cost and whether we're getting to the optimal results in terms of overall efficiency.

Question: If the state legislatures want to maintain their traditional systems, by overlaying kind of this merchant approach on top of that then there are two different systems. Is that possible, can it work?

Speaker 1: Well, it's already imposed. Not a merchant system, but FERC open access requirements. The question is are the right price signals being sent to customers in Utah in a traditional system?

Speaker 2: There's no objection to a planning or preconstruction prudence determination by a state regulator. It should be disentangled from the siting process. In terms of federal lands, there is some pretty clear indication that the Department of Interior wants to do everything it can to move forward. There's a more unified approach coming out of the Obama Administration.

Comment: If you are in any conferences in the west, the BLM [Bureau of Land Management] conversation dominates. There are quirky things like you cannot build solar panels because the reflection will get in the way of the Air Force bases. There are a lot of complicating factors. People spend days talking about this.

A second concern is deliverability related to renewables. It's an issue again in many conversations. The RPS debate in California was hung up because the conversation was about having to physically deliver the renewables into California. They couldn't just use RECs. That issue has not died. It is increasingly important as some states become more protectionist about trying to encourage jobs and generation development in their state, particularly for renewables right now. It is not necessarily directly tied to this transmission conversation but an issue that is resurfacing in the renewables conversation.