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HARVARD ELECTRICITY POLICY GROUP
FORTY-NINTH PLENARY SESSION

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RAPPORTEUR'S SUMMARY*

Session One.
Commitment: It's Getting Better All the Time with MIP

Each day system operators must decide what generators to commit and when to commit them. To a lesser extent they must make this decision for the transmission assets. Investments decisions are lumpy and must be coordinated. These commitments should be done in a way that maximizes the benefits to society. Unit commitment is a core function of all electricity systems, and the associated economic dispatch is a critical element of organized electricity markets. A bid-based-security-constrained-economic-dispatch including unit commitment is an optimization problem with an additional condition that some of the variables must take integer values, a mixed-integer program (MIP). This integer requirement—the plant is either committed or not—presents issues of computational difficulty, economic interpretation, pricing, and uplift determination.

The MIP has been long been recognized as a powerful modeling paradigm for electricity markets, but historically hard to solve. Over the last decade, in addition to increased performance for computer hardware, the performance of solution algorithms has improved dramatically. Explicit unit commitment through a full MIP is now being used in PJM's real-time and day-ahead markets and is being tested or scheduled for introduction in other ISOs. What are the technical improvements, and why should we care? What are the benefits of obtaining better solutions? How can the approach address improved bid functions, for example, for combined cycle plants, forbidden zones, and even new market designs such as those that allow transmission switching? What are the implications for energy and reserve pricing? How should all these impact the economic model and associated incentives for reliability and efficiency?

Moderator: In every organized power market and day-ahead market is the complicated problem of unit commitment, in large part because units cannot be turned "half-on." It's either turned on or it's unavailable to be used. This has implications for economic commitment

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

and dispatch solutions, and for how this is addressed in the context of markets and associated payments. There has been a great deal of work on this subject in the past few years, particularly in terms of the implementation of mixed-integer programming (MIP).

Speaker 1.

I'll be discussing the effect of unit commitment on market prices in the ISOs. Let's consider the way most of the ISOs in the U.S. are structured. The way they perform unit commitment dispatch and calculate market prices drives a need for an uplift. Basically, these prices don't provide the incentives that generators need to follow the commitment and schedule they get. The magnitude of the uplift depends on the way the market prices are set. Most ISOs have a day-ahead market based on bids. They set a schedule in the day-ahead market using security constrained economic dispatch. After the day-ahead market, an ISO will have a reliability commitment and, in real time, they'll dispatch using security constrained real time dispatch. Then they'll come up with locational prices for the day-ahead and real time markets for settlement purposes. The markets for energy and ancillary services are co-optimized to a greater or lesser extent, depending on the ISO. There is also a mechanism for financial transmission rights. ISOs want their day-ahead unit commitment and dispatch to support the implementation of least cost unit commitment.

This is facilitated by allowing generators to submit bids that match their plant operation characteristics. In addition to incremental energy costs, they also get to submit unique aspects such as start-up costs and times, minimum generation blocks, ramp rates and so on. Based on these bids, the unit commitment and economic dispatch programs are used to optimize the schedules in the day-ahead market.

Consider prices. If we assume that the day-ahead unit commitment is fixed, the marginal costs of serving an increment are well defined and easy to compute. This can be labeled the restricted marginal cost, tied to the given unit commitment. These restricted marginal costs don't include start-up or no-load costs that were submitted in the bids. If there is a small change to the load, this usually won't change unit commitment and there's no change to start-up no-load cost. The only thing that affects restricted marginal costs is the incremental energy costs.

This definition of restricted marginal cost means that they may not behave the way you usually expect a price to behave. As demand increases, one would normally expect price to increase. Restricted marginal costs may not behave that way. As demand increases over time, additional units will get committed and costs can go up or down. Further, there may not be market clearing prices. We always use the term market clearing price but it's not always accurate. If market participants saw the price without the ISO giving them their schedule after the fact, generators and loads would not come up with schedules at those prices that would balance supply and demand.

The discreet nature of these commitment decisions is one of the main sources of uplift in the market. These uplifts are necessary to provide incentives for the participants to follow the least cost schedules given the prices that the ISO sets. There may be increases to cover the costs for units whose costs at the schedule are not covered by the price. There can also be uplifts to cover opportunity costs for units that are not dispatched at their maximum profit point.

Let's consider a market with two units offering into the market. Each unit has two 100 MW blocks of energy. The first unit, G1, has no fixed costs. G1's first block of energy costs $65 in megawatt hours. The second block is $110. G2 has a fixed cost of $6,000 and then costs of $40 and 90 respectively for the two blocks. If the demand is 190 megawatts then G1 and G2 would both be committed. G2 would be dispatched at 100 megawatts for the $40 price, and G1 would be dispatched at 90 megawatts. G1 is the marginal unit and sets the restricted marginal cost at $65 a megawatt hour. However G2's offering costs are $4000 from the 100 MW at $40, plus the $6000 fixed costs; $10,000 total.

G2 would be receiving $6500 from the market for its 100 MW at $65. It's short $3,500. That uplift must be paid to the unit if we want it to follow that schedule.

In fact, there is no price at which G1 and G2 would maximize their profits to produce 190 megawatts. At prices between $65-95, G1 would commit to 100 megawatts but G2 wouldn't come on. From $95-110, G1 would produce 100 megawatts and G2 would want to produce 200 megawatts. At exactly 95, G1 would produce 100 megawatts but G2 would be willing to produce either 0 MW or 200 MW but not any amount between. There is no market clearing price for 190 MW.

How does one produce pricing and treat uplifts in these situations? People have tried different things. O'Neill and others have a clever restricted model which treats unit commitment as known and adds it to the security constrained economic dispatch. It has variables to model the unit commitment that incorporate the constraints.

The New York ISO's approach lets all the units be treated as if they were dispatchable down to zero. All the fixed and incremental costs are averaged out over full load to set the variable costs.

The MISO is looking at a convex hull model. This is because if the total costs were set at a convex approximation, then they are very close to the real cost curve. It sets a function which is everywhere below the total cost as a function of demand and as close as possible to it. That's more complex but it has some nice properties.

Each of these three approaches will produce different energy prices with different levels of volatility and uplifts of different magnitude. The restricted model produces the restricted marginal cost. In other words, as demand increases, that marginal cost can go up and up. It produces prices on the commitment constraints which we can view as components of an uplift.

The dispatchable model, that produces a nice marginal cost curve that behaves as we would expect. As demand goes up, the marginal cost goes up. It behaves the way you would expect a market to behave. However, it can lead to larger than necessary uplifts.

The convex hull model produces an energy supply curve whose marginal costs increase as load increases. It leads to a minimum uplift. For that example I was talking about, the total cost varies as demand increases. Between $100-200, the cost ripples; it doesn't look nice. The slope goes up and down. As the price increases between $0-178, you only commit G1. At 178 megawatts, G2 is committed. Once G2 is committed, the high price energy from G1, is replaced with cheap energy from G2 and marginal cost drops again. Then, it slowly catches itself back up. Marginal cost varies extensively with all three models, and seems to be slightly higher with the convex hull model.

However, the convex hull model reduces uplift costs extensively and seems to provide an advantageous approach. That's not an accident. The convex hull prices the demand constraints with function. We're forming a partial function that is maximized over the prices. What's interesting is the approach to the Lagrangian relaxation of the unit commitment problem. These used to be the state-of-the-art unit commitment algorithms in the 80's and 90's. Then people moved to full mixed integer pricing. However the Lagrange multipliers are used to help set prices that minimize uplift. The hull prices minimize the uplift because the convex hull model is produced by the unit commitment. It minimizes the duality gap and the duality gap is the level uplift we need.

So what's next? The basic math is set for this and further investigations of these alternate pricing approaches are needed. MISO is also hoping to have this handle transmission constraints. They want to simplify the convex hull problem when there are those transmission constraints. Those are the upcoming challenges.

Speaker 2.

I'm going to discuss bid cost and mixed integer programming. Around 1970, digital computing entered the electricity business along with fiber optics and the internet for communication. Further, size was not as much of an issue in the generator market and smaller size became OK. The combination of these factors is why we have ISOs today with the switch from cost base to market base.

The ISOs hope to make the market work better. What's at stake are two trillion dollars a year in revenues. A 1% efficiency gain in these markets means billions of dollars. The general optimization model for electric utilities involves non-linear functions and integer variables. It's a very powerful paradigm; you can model just about anything except it's very hard to solve. Mostly the industry has used Lagrangian relaxation and linear program.

Linear programming has been described as a hammer looking for a nail. It can be solved, and quickly, so consequently everybody wants to use them. In 1996, grid operators could solve a 300 node problem without transmission constraints. Solution times are now about a million times faster.

One of the approaches for solving integer variables involves "cuts." The Gomory cut, which has been around for 30 years, is still the best. Now MIP allows us to solve much larger problems and gives us a better modeling solution for start-ups, for transmission switching, and even investment decisions. It solves problems with tens of thousands of nodes, constraints, and binary variables. Let's consider an old 1993 one day unit commitment problem. At that time it would run for 1600 seconds and still not produce a solution. Now it takes software less than a second to do this. Similarly with one week unit commitment problems. At that time they were essentially unsolvable. Now such a problem takes less than two minutes. The general rule for ISO market solutions in the day-ahead market is that two hours are allotted for this determination, so it's become easy.

The ISO's get much better detail in their ability to model the real time market. These solutions are better and save money. PJM estimates that MIP saves about a hundred million dollars a year in the real time market. Four of the six ISOs are planning to move to, or at least test, mixed integer programming.

It also improves the ability to model end use markets. Industrial customers are not the only entities with non-convexities. For instance, an industrial firm may want to run a shift for eight hours or not at all. That's a very lumpy decision. These demand side representations can now be efficiently integrated into real time and day ahead markets. The monetary savings are truly significant.

Marginal cost curves occur a lot in these markets and if you're a neo-classical economist, this will drive you crazy. Often, these cost curve models are also discontinuous. Instead, the bid start is set at the start of the cost curve and extensive variation is taken out of the market.

The curves generated by MIP are similar to residual demand curves; what the market looks like when the generator's facing the demand netted with all the other generators. These are much more optimal solutions. In a lot of these markets, the generators are sitting at their minimum at times when they should be in a higher range.

Transmission switching is another challenging area. The New England ISO has been working on using MIP to get the optimal topology. They get savings from one to 25%. In the New England market this is up to $500 million per year. Even if the ISO is spending significant money developing MIP the savings make it a no-brainer. The same thing is possible for the capacity markets. On a worldwide basis the potential behind MIP for improved dispatch is somewhere between $10 and 200 billion a year worldwide.

So, market clearing can get problematic because linear prices don't clear the market. Most ISOs simply have a payment and charge everyone the average load. If the demand side is in the market, this violates confiscatory rules of most markets. These sophisticated MIP approaches present a much better solution to the cooperative theory problem of how to allocate the costs.

Obviously, this is new stuff, as PJM has already implemented it. I expect we will see improvements in its implementation. Further we may even see this approach being used on still unsolved problems like mixed integer AC optimal load flow problems. There is a great deal of promise.

Speaker 3.

I'm going to discuss why PJM decided to implement MIP. In 2000-2001 they knew their market size was about to double from 500 generators to 1200. They were concerned about demand response customers who would need to use strip bids, bids with constrained parameters. For instance, curtailment minimums of four or six hours. They knew their equation problems were going to become much more complex. PJM asked for MIP and there was initial skepticism but initial planning started around 2004.

In May of 2004 they began parallel operations using both MIP and Lagrangian relaxation [LR]. The MIP solved faster than LR in almost every market. The operating people who were initially reluctant were soon asking to retire LR as quickly as possible. The solutions were much quicker, and that was a side benefit.

MIP was soon implemented in the day-ahead and reliability commitment arenas. Their day-ahead market includes all the virtual bids and the reliability commitment actually is run later in the day. Both go out seven days and commit for an entire week. Once it became clear that this worked, the question was for real time. They wanted a computer running the system, not system operators – they would only be needed to troubleshoot. That's not yet the case, but it is the goal. In August of '06, MIP was implemented in real time. The LR was a manual process that they ran on a periodic basis in real time. That manual process is gone now. It is more automated now under the MIP.

The next goal is perfect dispatch. One of the challenges for PJM is to determine how well they are performing. MIP, under a full dispatch regime will be able to help with that. They can hook up the computer and let it run as if it had perfect foresight. On the day after the operating day the computer gets all the previous day's information and analyzes it completely with MIP. It gets used to run dispatch, and it also gets used to analyze it after the fact.

Benefits of MIP include the following: global optimality, accurate solutions, improved security constraint modeling, enhanced resource modeling for generation, demand response, and transmission, and more adaptable problem definition. In the day-ahead market, they couldn't model every transmission constraint. LR couldn't solve it. With all the transmission constraints, MIP actually solves problems faster. Since PJM's market is becoming more transmission constrained, this is a great benefit. The same with hydro units and pump storage. They can get bid into the market reliably and fairly. Similarly with demand response.

The last is adaptable problem definition. PJM was concerned that they had such a wide variety of different problems in the future, each which would require different kinds of solutions. The MIP approach is adaptable to a wide range of market types and conditions. They don't have to retro-fit it for different situations or get new software.

After PJM implemented MIP in late '04, there was a dramatic reduction in market uplift costs – almost 50%. These costs are uplift that is socialized into the market; it is bad, unhedgeable. Participants can't predict these costs, so it's considered bad for markets generally. When MIP was put in the full transmission model, and the day-ahead solution, there were immediate results. Similarly for real-time and reliability commitments.

MIP tends to solve faster with a more complete model of transmission. In fact, their models run with essentially the same transmission model that they use in dispatch. Unit commitment and dispatch are not separate. Initially, MIP could not handle conditional constraints well that LR could. For instance, hot, cold, and intermediate starts; things like that. Certain constraints gave MIP big problems. Finally they just eliminated the constraint. They didn't even need the model. They just put in the actual characteristic.

PJM has a new combined cycle and hydro model that could not be used in LR. MIP does it, and the increased speed is simply a side benefit. Looking forward there will be growth in demand response and distributed resources. They expect to be able to handle those just as easily.

Non-traditional regulating resources, like hybrid vehicles, are expected to be a challenge. PJM expects MIP to address this fairly easily, and to allow that kind of technology to come in. It can also accommodate regulation. Turning somebody on regulation or off regulation is a commitment decision. PJM does that every hour but it can easily be done more frequently. Generators complain if regulation switches occur quicker than an hour. However, this can be adapted at a faster pace if necessary. MIP will also be used to do a better job of interregional coordination. Currently, PJM shares constraint information every 15 minutes. MIP will be used to expand and improve capabilities in this area, as well as many others.

Speaker 4.

I will discuss the California ISO's experience with unit commitment. It is similar to PJM. In 2003 they were proceeding with a market redesign and technology upgrade. They were creating a real time day-ahead market that was full network with an AC solution. They also needed to model those resource constraints adequately. Vendors offered Lagrangian Relaxation solutions and MIP as well. The biggest concern was that MIP was untested, and performance was still unknown. PJM hadn't implemented their system yet.

The ISO went through a proof of concept process with the vendors to determine if the two approaches would be adequate in terms of solution and performance. The MIP approach performed well. Timing was good, and the MIP gap relative to the duality gap in Lagrangian was good. They were getting 0.5 to 0.2% solutions. They proceeded with MIP and also maintained an LR solution as a backup. There wasn't a huge cost differential, both could be implemented. Currently, their plant implementation date of MRTU with the MIP is April, 2008.

MIP allows them to model a large number of constraints. They have capacity to model up to 2,000 binding constraints over a 24-hour low play interval optimization with up to 150 contingencies. They can model nomograms with MIP. Nomograms are simultaneous limits on transmission interfaces and generator output. They are more complex than standard normal flow limits. Whether you procure ancillary services or energy from a resource is also a commitment decision that benefits from MIP.

Dynamic ramp rate models are also implemented. A lot of their resources don't have the same ramp capability for the full range of the resource at different operating ranges. There are different characteristics at different operating level ranges. There is an integer variable decision to make each time, whether to move into that range and accept the new ramp rate for that range. This is even a challenge for MIP although it has potential.

Resources also have on-off decisions and forbidden regions of operation. Some units, because of feed water pumps or other characteristics, can't operate in a given range. They can move through the range but can't stay and dispatch from a particular range. That creates challenges that MIP helps solve.

MIP also helps with energy limitation constraints. The ISO can take a certain amount of megawatt hours and dispatch it to minimize the cost and maximize the profit of the resource that's offering a limited amount of energy. They could not do that with the Lagrangian approach.

Pump storage modeling is similarly improved. The decision to pump or generate with a pump storage facility gets modeled more effectively. They have several of those and it helps make those decisions.

Lastly, constrained output generator dispatch and pricing are also modeled better. These are resources that are on or off. Typically, they don't set the price because they're not marginal. However, the ISO allows them to set the price because of special features in their system that allow for it.

Let's conservatively assume MIP provides just a 0.1 to 1.0% improvement. A 1% improvement is $23 million, assuming 80% of the market is self-scheduled. These savings incorporate the ISO's dispatch costs of real time, residual unit commitment costs, and their current day-ahead market. They don't really have an energy market today, they just allocate transmission. These cost reductions could also get implemented in the self-scheduled or bi-lateral portion of the market.

California does not have a capacity market currently, just a resource adequacy obligation at this point. A capacity market is being considered going forward but that future is unknown. However, they do expect that MIP will help make the ancillary services market more efficient going forward. Finally, there are no immediate intentions to introduce MIP to the planning process but they will continue to evaluate that.

They are right in the middle of testing solutions. The model testing has so far accounted for 35 integer variables, that's with 2000 binding constraints over 24 hours. For the day-ahead market, which optimizes 24 hours at once, the base computing time completes in one hour for multiple passes. The multiple passes account for market mitigation, reliability, and an integrated forward market, which is the bid-in market for energy and ancillary services. After that, there's a residual unit commitment, which checks ISO forecast load. Each pass has iterations back and forth between the unit commitment decision and the network application AC solution. One hour is a good solution time. If necessary, they could look at the results, run them again and still meet timelines for publication.

Real time unit commitment runs every 15 minutes up through 18 intervals which can be approximately 4 to 5 hours. They are getting solution times of about 12 minutes. This has a market power mitigation pass, a unit commitment, and SCNA iteration passes. In real time the ISO is basically doing just dispatch of energy. They have it running every five minutes for performance levels, with a linearized version of the network model. They don't update the network model every five minutes but they do an energy dispatch. In the five minute period, they're getting solutions in about 2½ minutes, which is right on target.

In the day-ahead runs, MIP gaps solutions are in a range of 0.2 to 0.5%. When they were starting the simulations, they didn't want to put all the constraints in the system. They thought it would overwhelm the system. It was taking a long time to solve. Ironically, when they threw the 115, 230, and the 500 kV constraints, it solved faster. They thought, "Wow. Is it coming up with the right number?" The constraints reduce the potential solutions and reduce the set-down the optimal solution comes faster. That was an unexpected benefit.

The ISO hopes to use MIP in some of the market initiatives. They will be modeling more robust combined cycle modeling with various unique constraints. If the ISO is going to put pressure on generators to perform, then the modeling has to be much better. MIP will help with this.

Demand response can be impacted positively, as the previous speaker mentioned. They are willing to participate but have unique characteristics. If they get curtailed then the curtailment has a minimum level of commitment. MIP can really model these appropriately.

They're obligated to provide an increased number of ramp rates. They provide four ramp rates ranges now but they're obligated to provide up to nine in the future.

Enhanced forbidden region of operation. I discussed the fact that some generators can't operate in certain regions. However, others can but with a minimum time threshold. The generator says, "Well, if you move me to that forbidden region, you gotta hold me for a certain period of time." They hope to use MIP to create that as an additional enhancement feature.

Transmission priorities will also be incorporated into future modeling. In California, existing transmission contracts, transmission ownership rights, self-schedules and reliability must run resources create highly varied priority needs. Integer variables may do this better than penalty functions.

Finally, the last agenda item is the potential for multi-day optimization. Optimization over 24 hours can be insufficient for long start resources or resources with characteristics that could cycle from one day to the next. The operator is bouncing back and forth between two resources because it can't cycle back on for the next peak day. A multi-day optimization would help smooth that out. There's an enormous amount of application and potential utility for the MIP approach.

Question: As the load gets higher and higher, with more output and more units involved then the size of the lumpiness problem becomes smaller. The implication of this is that these problems don't exist in a large system. Steve Stoft wrote about this several years ago. It becomes smoother and all the complexity of dealing with MIP isn't worth the trouble. We should just avoid it.

This seems logical. Alternately, this only works if it's a big enough system with high enough flow. However, most of the time an ISO operates in a different part of the load, with smaller volume. Which characterization is more applicable? Is going to all the trouble of implementing MIP really worth it?

Speaker: High volume operations don't always smooth out. Transmission constraints can make operations even lumpier and separate a large area into separate geographical regions. As a load gets higher, the difference between the minimum load and the maximum load – the actual ramp throughout the day – becomes bigger. This creates its own set of problems when there are more units coming into the mix to be turned on and off. This counteracts the smoothing that you described. The transmission separation is the more critical of the two issues though. Under old commitment planning, everything was addressed via a subset of transmission constraints, it had to be. Under these new models, the full transmission can be accounted for and it's more efficient.

Speaker: I would emphasize the ramping issues just discussed. Current systems do not price changes that need to happen and ramping capacity that is needed. Operators really need a ramping product. They buy ancillary services but those do not account for differences in ramp capability.

Speaker: Transmission constraints are really a problem. Operators have to commit resources to manage these and once the resource is committed, it pulls the flow on the constraint under the limits so that it no longer appears to be binding. It is either overloaded or non-binding. Constraints screw up prices. They are financially binding but lumpiness means that those constraints are not priced into the market. Both NEISO and MISO have that problem. The constraints also make the problem function on a small region level.

Speaker: Ask an operator, "how do you know Lagrangian Relaxation is getting you a good answer?" The truth is you can't tell. With MIP, you can show how close you are to the optimal solution. It's generally about 0.2 to 0.5% away from the optimal solution. You can't do that with LR. You can't assume the lumpiness out of the market, you have to deal with it. MIP does that, LR doesn't.

Question: Is there a limit to how far one could constrain the requirements of the solution with MIP? For the day-ahead market, it's a financial solution. Is there a limit to the elements you add to the market? They provide different solutions but can they constrain the solution more? In

PJM's context of virtual-type path bids, one could imagine a host of other transactions.

Is there a way to provide more versatility to real time transactions? Sometimes there's a willingness to pay congestion transactions, or other types. There's a host of new ways of discriminating between which transactions an operator will accept in a real time solution; mainly import or export transactions. Could this help address seams issues? What are the limits there?

Speaker: Can we distinguish between bids that would constrain the solution and path bids? What does that mean?

Speaker: Path bids are not unit commitment problems but a dispatch problem. Path bids are price spreads as opposed to up-to-congestion bids; they bid a spread. It's not a unit commitment problem.

Speaker: Why does it constrain the solution?

Speaker: If there's too many, path bids create problems for the dispatch software.

Speaker: So, it doesn't constrain the solution. It's just more complicated to solve.

Speaker: Some constraints are not based on unit commitment, and don't need solutions from MIP or LR. For instance, a blocked bid where a generator will take a minimum number of megawatts for a certain number of hours. This kind of complexity requires a unit commitment algorithm. Other parts of the problems just described are a pure dispatch problem and a total volume problem.

In PJM, MIP allows more flexibility to demand responders, especially in the real time market. Performance of the unit commitment in real time isn't a real problem. In the day-ahead coordination with other RTOs, PJM's operators are so confident in the MIP software, that they reduced the amount of regulation required. That's a combination of the MIP and the AC power flow software.

Speaker: There are overly constraining situations on two fronts. One is self-schedules, where lateral arrangements don't provide for flexibility of movement. At some point, operators may need to reduce those and get a process to do that. But, prices will reflect the reduction in self-schedules. Self-scheduling practices may change because of that.

Second, ramp capability is a true constraint. It's physical and also reflects difficulty in getting the right mix of resources. There are times when there is not enough ramping capability to meet load ramp or interchange ramps. Prices reflect that. Behind the scenes, the software is struggling to get a solution and meet its power balance constraint.

Speaker: In PJM it was hard to get combined cycle plants to figure out how they wanted to model their units once they were told that the software could accommodate much more varied situations. It did require work on their part to develop these models. Now that they have seen how well it works they are enthused, and other generator owners want PJM to adapt their models for their fuel source limitations. For instance, some coal plants use gas as start-up fuel. It's encouraging.

Question: How important is programming and software speed as a qualification of these solutions? Second, what's the for demand response in these systems? Will MIP keep up?

Speaker: The big incentive in PJM was the fact that LR would not let them add a lot more generators or demand response. They would look silly if they had a competitive market that couldn't handle a large amount of competitors. Now they can handle thousands of generators and demand response players. They might take a small hit on performance but performance is so good that it's not a big loss.

The solution speed is important for the day-ahead markets. They can close the market at noon and post at 4:00. They could do it in two hours. That is extremely helpful for transparent efficient market operation. A commercial perspective; how quickly does a market get their answer. Further, from an operational perspective, they need the real time unit commitment in under five minutes. It cannot be longer than five. Right now it's between 30 seconds and a minute.

Speaker: That's the real time incremental commitment. Obviously the day-ahead runs in 20 minutes.

Speaker: There's two interesting facts. First, when more constraints are added to the system, MIP solves the equation faster. Second, it's not actually solving the problem yet. There's between 0.2 and 0.5 percent of the benefits still on the table. That's a lot of money.

Nonetheless, there is significant overall benefit here. The reductions are in inefficient unit operation. Previously, there were units that had to be partially compensated via an uplift. They were running above market. The consumer side of the market is seeing a benefit. In the context of PJM, it's around $200 million that they aren't paying in uplift that previously paid.

Question: In California, there's a lot of discussion about ramping. They're also considering non-market based solutions for ramping. They're many hydro resources. What is the issue with ramping? Are there not enough resources? Is it a similar problem in other markets? How do we get resources with needed ramping capabilities?

Speaker: In the West the interchange ramp policy has not evolved the same as the East. They get one shot per hour to change their net interchange with neighboring balancing authorities. In the East they can spread it out over 15 minute intervals.

There's a lot of hydro in the West, but not all is available for ramping and dispatch. Some of it's run over the river, some has storage facilities and then there is available ramping. The regulation and the ramping capability is being picked up by those hydro resources. A low hydro year or spill conditions obviously changes that.

The software is not the problem. The software grapples with a situation does the best it can. Honestly, consider a unit that has 10 megawatts per minute, and then drop it down to one megawatt per minute for another 5 megawatts of operating range and then back up to 30 megawatts per minute through another operating range. That is the real challenge.

Speaker: The root of the problem is more administrative. the way California allows ramp to occur is restrictive. The hour versus the quarter hour, it's much more restrictive.

Speaker: MIP allows virtually any kind of dispatch pattern. The only cost is developing more complex bid strategy, or capabilities and possibly more computational complexity that may slow the solution time down. There's virtually nothing you can't model The only concerns are if it gets so complicated that solution times actually slow down. It's also a question of how much is it worth for an ISO to implement all these gory details.

Speaker: The MISO has a twofold problem with ramp. They allow a lot of flexibility in the offers and some participants restrict the ramp on a unit, below ramp capability. Second, they only solve economic dispatch for periods ten minutes away. There's no look-ahead. They use up cheap ramp capabilities short term, and don't' hold it to be available in later periods. They expect to address these problems very soon.

Speaker: Other ISOs look at a five minute interval, but also two hours out. If they see a ramp coming they can position resources to be ready for that ramp. However, even that creates questions of prices. If they start moving a slow moving unit early to be prepared for the ramp, it does create perceptions of uplift because the price will be potentially lower than what their bid is.

Speaker: Does MIP have applicability in a cost-based system? Instead of getting a marginal bid, a market bit, it's in input based on actual cost as assigned or determined by somewhere. Could MIP help in this context?

Speaker: A side point to all this is that market competition, driven by ISOs and market participants, is what got us this MIP solution. It's not a robust program in the vertically integrated utilities. They think their operators are doing well, and they don't care that much about least-cost dispatch. Folks in that world have told me it's not on their agendas.

Speaker: If you look at the bid stack at PJM, 90-95 percent of all generators put in bids at their marginal cost of operation. There is very little markup on a day-to-day basis. In any large scale market, MIP makes it more efficient, either cost-based or price-based.

Question: First, I want to respond to comments about whether utilities care about costs. My experience in the utilities out west was that they seriously attempt to reduce production costs. For instance, the modules that produce the ABB tool minimize the total production cost for the day-ahead and weekly commitment. They do this above and beyond the dispatcher's knowledge.

Second, MIP appears to reduce the total bid cost. Who is the beneficiary of these price reductions? PJM has virtual bids in the market. They are purely financial, with little or nothing to do with the production costs of the electricity. Minimizing the total bid cost is not equivalent to minimizing the production costs of the system. The total cost for consumers in the PJM market is the total energy payment plus the total ancillary service cost and the uplift cost. So who benefits?

Speaker: Very simply, society benefits. Whether individual entities benefit is much harder to determine. Overall, the costs to society go down. The money may move around inside the system.

One of the principal reasons PJM has financial bids in the market is to solve the problem where large utilities were accused of taking advantage of the market structure. They could bid less than their full demand in a day-ahead market, lower the market price and then have to buy more in the real-time market. It's not clear that this happened on purpose, but it has happened. The financial bids correct this concern. However, they do create a conundrum because they can force an operator to commit or not commit a unit that doesn't belong in the dispatch. That problem still needs to be addressed.

Speaker: In the day-ahead market, you have virtual bids in play, but the MIP implementation in the real-time market has no virtual bids. The real-time market is geared towards physical resources and demand. MIP in the real-time market is truly a reduction in the production cost. We know of production cost savings around $100 million a year in one ISO. LR simply could not model a transmission-constrained operation. It's a direct savings and benefit to consumers.

In a day-ahead market the reduction in uplift is important. Uplift is essentially payments being made to generation for running out of market. It's generally just offsetting what their bid was. They are generally bidding cost. Uplift in most cases is getting reduced by about half. Again, that's about $200 million that the customers didn't pay.

I have not put those estimates in my descriptions because I was evaluating MIP from a bid cost basis as opposed to a bid production cost base, because of financial bids in the day-ahead market. For ancillary services, savings are much more modest because ancillary services themselves cost less, those savings are almost negligible. Most of the savings with MIP and ancillary services are giving the dispatchers confidence that they're deploying the best operating state they have.

Speaker: Operators want to ensure they're sending incentives to people to bid accurately, number one, and to have bilateral contracts. They want to be sure that even if there's a bilateral contract, if the energy is cheaper in the market, that unit should be on. The ISOs need to support these bilateral contracts. In MISO there's activity in their financial bilateral transactions. The price doesn't tell you the winner and loser unless you examine the underlying financial contracts. That's the only way to get a complete picture.

Speaker: Virtual bidders do this to arbitrage between the day-ahead result and real-time result. Any financial player that forces a unit commitment to occur which is inefficient will face consequences. If they put in a high purchase bid, forcing a unit to come on that shouldn't be on, they'll be on a credit call very quickly and get kicked out of the market. Virtual bidding, with low barrier-to-entry participation, makes it more efficient. The real-time market sets the standard. Day-ahead financial participation helps things.

Question: Can MIP be applicable in addressing additional constraints; like greenhouse gas, operation, or anything like that? What other applications are there?

Speaker: There have been some applications of this to the SO2 market. They have lumpy economic decisions to put in scrubbers, a big capital investment, versus buying credits in the market. MIP has been used in analysis to get appropriate strategies. Planning models are possible too. For example, the ICC models have a different set of options than a coal plan with sequestration. The scenarios can be modeled much better.

Speaker: There is potential for future IDCC models and wind operational issues and modeling. Discontinuities that are brought by wind resources are difficult. This is still early research.

Speaker: How is this being used for demand resources? It seems like we're dipping a toe in the water out here. What's in the future?

Speaker: Some of the early barriers to entry were logistical limitations. Industrials or commercials would need assurance of a minimum amount of time to be down. A lot of the problem was just convincing people that they could be a demand responder. The ISOs and the C&I folks needed to have discussions about capabilities, modeling, and requirements. Those didn't always work, but a lot of the process has simply been education. Telling providers, here's the kind of things an ISO can model: notification times, blocks of time with minimum run, and minimum loading, i.e. a base amount of megawatts that will be taken. With MIP in place, it can be done on a larger scale because the modeling is so much better. The ISOs can aggressively go after demand response now because they know they can model it, even if there are thousands of participants.

Speaker: California's currently defining what demand response would be in the future. It's lumpy, with many decision challenges. They are trying to figure out how to model a three part bid where there's an event cost that takes the action of reducing the load, and a going forward cost, how much they pay to stay off cost, and an incremental cost, how much if they are reduced further. This kind of bid modeling has real business meaning to loads that are considering DR participation.

Speaker: MISO is also working to increase demand response. Their big challenge is that they already have a fair amount of emergency demand response capability. When they called an emergency, the operator would have to forecast how much they would need. Perhaps they needed 3,000 off and asked for 3,500 megawatts. All of a sudden the LMP's dropped and buyers were saying, hey, I bought this day-ahead at a high price and now we're being forced to pay it back cheap.

MISO is trying to figure out how to address this, and how to price it, particularly if they have to call on people a couple hours before real time. Figuring out these pricing issues for demand response is important.

Speaker: Does that help an operator get better scarcity signals?

Speaker: The MIP alone doesn't do that. If they just looked at the price in the period, they might be calling on it three hours before the period, and that's based on a forecast. They're also doing the calling on demand response with a notification time. They have to address and blend the forecast-based curtailment call that's made at one period with other actions that are made in subsequent periods. They all affect that one real-time period. We've got to get that all blended together.

Speaker: With demand response, the simple answer of assigning everybody an average cost uplift goes away. Assume demand response is bidding into the market, let's say for $80. They may find themselves being in the market and paying $81. It's a confiscation type issue because they didn't want to pay any more than $80. The operator has to tailor the uplift allocation. It is a more challenging problem. Since there is not yet a lot of demand response in the market this concern hasn't had to be addressed, although the issue has come up with virtual bids.

Speaker: There are two companies within PJM in the past year that went public solely as demand response providers. It's now a commercial operation, a business. Soon PJM will break the 1 percent demand response penetration. It's a start. For the folks doing this as a business, MIP really increases their level of confidence and the consistency of their market. They can start selling DR with gusto. It's a real paradigm change.

Speaker: Operators can offer industrial customers very complex strategies that conform to their business strategy.

<u>Question:</u> This is a market power question. In the simple model with variable costs, operators worry about people bidding higher than their variable cost in order to manipulate the outcome. We heard that in PJM 95 percent of the bids are cost-based, but there's always the possibility of mitigating those bids. If they introduce multipart bids with start-up and minimum run and ramp, all these parameters, does it introduce more possibilities for manipulation? Does it make the market power monitoring mitigation and so on easier or harder?

Speaker: There's been a lot of thought about this. When a bidder is restricted, for example, they can't bid their ramp rates, they overstate it because they're not compensated for it. In the research I've seen, it seems to be harder to figure out a gaming strategy because the market can flip very easily. For instance, if they're bidding above their cost, they may find themselves being required to generate in the market at $50 when their cost is $50 and the market price is $20, There's a lot of zero one decisions that change things a lot. It is much more difficult to develop an intelligent market power strategy. the hope is that this incents people to bid cost and make money because they are a more efficient generator or because they can respond better to certain events.

Speaker: Initially, it makes market power mitigation and monitoring more difficult. There's more interactions and people will be inclined to experiment and see how they can profit from those levers. Things will settle out over time. If it's designed right and appropriate actions are taken for those who exercise market power, it should settle out. The beginning will be the most difficult.

Speaker: In the past PJM had some phenomena to address. For instance, a generator in a certain area who knew they were needed for transmission limitations. They might change their min run time from 3 hours to 5 to push the limits of the operator decision on unit commitment.

PJM's first responsibility is to operator performance. Making a real time decision to maintain reliability. In the past an operator would go with "the unit of the week," whatever generator that was their favorite unit because it solved the problem they had yesterday, and the operators didn't have good modeling tools. MIP has solved that concern. MIP has really reduced that kind of imperfect discretion and optimized those decisions.

Market monitoring with complex bidding, meaning start-up, no load, that's always going to be a challenge. MIP doesn't make it worse, and it certainly made operators' decisions more trackable.

Speaker: In the initial California ISO market design, the day-ahead market, they couldn't bid start-up or no load cost, they had to bid a single price. If somebody's exercising market power in that market, how do we mitigate them, because their bid strategy has to include recovery of their fixed costs. You can't legitimately mitigate them to bidding their marginal costs because they may have recovered all their start-up cost in the market. With MIP those true costs are easily reflected in the bid, market power mitigation is more complicated if you don't let the generators represent their true cost in the market. MIP allows them to do that, it improves the market power situation.

Question: With demand response, what happens in a world with advanced metering infrastructure? This could mean millions of points of demand response.

Second, some generators can begin to look like demand response. For instance the operator has the ability to cycle off certain loads for fifteen minutes, half an hour, but have them come back on, to potentially use them as spinning reserves or regulation. They have a different look and feel than if one were using a generator to provide that service. What are the limits for doing this with MIP?

Speaker: With MIP some ISOs are looking for 7-10% demand response in the future. The smaller nodes are expected to come to the ISO via load aggregators. If it's aggregation it's fine. There shouldn't be any problems there.

Speaker: The software that MIP replaced was very specific to the electricity industry, and thus very expensive. MIP is generic software, there will continue to be performance gains. The biggest constraint is figuring out how to do it from an IO perspective. The software won't be a problem.

Speaker: The challenge is trying to predict how much you're going to lose at a certain price level and when it will all come back. It can be large amounts, all at once. I suspect you could get into control problems. It could look like wind.

Question: Some speakers expressed the hope for big savings in transmission switching. Is this in the future, on the cusp, or in play. Where are we at with all this? Is it operational?

Speaker: These problems are potentially 17 hours today. They are not yet practical in their full-blown glory. However, optimization and improving the system is quite close. One recent academic paper took a 118 bus problem and got a 25 percent savings in dispatch. This includes reliability with all the N-1 transmission constraints in. Then they got the New England ISO model, which has 4,000 busses. It's still small in comparison to some systems. Nonetheless they were able to gain savings in this model also.

The editor of one academic journal claimed the approach was only theoretical. Obviously they didn't check with PJM. PJM already has a special protection system where they flip transmission elements in and out of the system. Reliability folks still want to be sure it's all working properly. When they switch a transmission element out of the system, it doesn't go away, and if they have a problem they can switch it back in immediately. There are concerns about how much you shock the system by switching it back in immediately, that's the current concern.

Speaker: The biggest challenge for larger scale transmission switching is cascading events. PJM already does transmission congestion control if the switching is automated, no human intervention in the switching. Cascading events are obviously a concern. To get the reliability community comfortable with large-scale transmission switching as an operational alternative will require other work. One has to guarantee all the relays will come back in. Besides the math modeling there's a lot of work done to be done in terminal equipment and the ability to deploy switching. More sophisticated hardware will be needed.

PJM does have SPS, the special protection scheme, to ensure reliable transmission switching. However, more will need to be done. It certainly has potential to decrease what I'll call regional operational cost.

Speaker: There is also the outage coordination issue. If they're planning outages that have impact on re-dispatch costs, then the way in which one schedules or re-schedules them can be adjusted to minimize the costs. That's a touchy subject because transmission owners set up their crews to do work on a certain day. It's very hard to shift work around. If there is flexibility then MIP can help do that also.

Speaker: At MISO, cost is not considered in outage coordination for transmission. They should, and MIP would be useful there. They also need to consider what it's going to do to their FTR markets. Right now that is just totally ignored.

Question: Can the ISOs use MIP and minimize the total and the permanent cost directly, instead of bit cost. Second, has PJM seen behavior changes in their market?

Speaker: They have seen behavior changes in bidding. Generators have tended to reduce their restrictions over time. They are realizing that the scheduling is more efficient. If they used to have a five hour min run that PJM would use in the past, now they won't. If it has five hours they won't take it, if it had four, they will. Generators are having to push themselves to compete. There's improved discipline in the generator community there.

On the other question, are you saying deploy MIP to price differently, instead of pricing energy?

Question: To minimize the payments, not the production cost.

Speaker: I'm not sure you need a MIP for that, that's really a question of how you set price. PJM has not discussed having a different type of pricing algorithm. The have talked about scarcity pricing, but not the fundamental underneath it.

Speaker: Philosophically, we maximize the benefits to society and then if we don't like how the benefits are distributed, we re-distribute the benefits. That's more of a political question than an analytic economic MIP question.

Question: Everyone knows we're not building transmission fast enough, that demand response doesn't have incentives, that generation isn't being built. Does MIP create more headroom while we wait for new development, or is it just really a cost issue? Does it improve incentives to build?

Speaker: If there is a feasible solution that wasn't feasible before, it is now with MIP. It does maximize what we have now.

Speaker: It makes better uses of the resources that it has. Independent of how fast new resources come on, existing resources are better used.

Speaker: It's not a magic bullet, it doesn't create capacity. It has lowered the operating margins. If they're operating at 95% of the reliability limit, now they're operating at 97.5% of the reliability limit across the board. It's much tighter. It's not all due to MIP, other advances and some of the AC algorithms have also helped.

Session Two.
The Impact of Competition on Electricity Prices: Can We Discern a Pattern?

Some proponents of competition in electricity argued that opening up the market would lead to lower prices for consumers. To what degree, if any, has that assertion proven to be correct? To push the question a step further, has the level of competitiveness in the market made a difference in the prices paid by consumers? How, given all of the variables, can we answer these questions with any degree of intellectual certainty? One hears that prices on non-restructured markets are lower than in restructured markets. Does that tell us anything at all, given that the status quo ante, pricewise, was a driver of the decision as to whether to undertake market reform?

Similarly, one hears arguments that relaxing regulation inevitably leads to efficiency gains that produce lower prices for consumers. Is there any merit to such ideological contentions? On a more sophisticated level, what impact on prices has resulted from variations in market rules from one region to another? To what degree can we reliably compare prices found in current market conditions against prices that might have existed under a different market model? In making such comparisons, how do we manage such variables as differing ways of allocating risks, varying external impacts such as weather and prevailing economic circumstances, service quality, and the prices of fuel and other materials? Can we know with any degree of certainty whether consumers are paying higher or lower prices today than they would have paid had there been no restructuring?

Speaker 1.

I'm addressing this as the big picture question. Is this working? Is electricity restructuring a good idea? What's happening with it? It goes a bit beyond the question of did it lower electricity rates. I'll address why one might think of those as slightly different questions in a second.

It's very difficult to determine whether electricity restructuring has worked by looking at rates. There are all sorts of time lags built into the rate structure. In California there are still non-trivial aspects from QF contracts and nuclear investment, let alone the 2000 electricity crisis. Determining when the impacts of a specific policy feed into a rate impact is very difficult. You have to control for diversity in starting conditions as well.

First, we have to ask, what do we mean by restructuring? It has many incarnations. It could mean LMP, it could mean mixed integer programming, retail choice, or capacity markets. It's very hard to differentiate the different aspects of this by looking at just rates, because all these things mix together.

I'll focus on one particular problem, the market timing or the perfect hindsight problem. Probably the key aspect of electricity restructuring is the notion that we're moving from cost-of-service regulation to market-based pricing, or generation. A regime in which the recovery of the cost of building, owning, and operating power plants is guaranteed changes to one where we're basically paying power plants the going rate or the market clearing price for the electricity. At different times, eras, or conditions, one approach or the other will be a better deal for customers. It has to do with when the debate is occurring over a long period of time.

The average retail price from EIA of electricity over the last 40 years had two periods. One was where the nominal price was around 2 cents. Then we had the 70s and 6 cent electricity became the norm.

The marginal cost, the cost of the last unit of electricity in a system is the market price for electricity, if markets are working right. The marginal cost varies in ratio to retail prices. There are eras in which the system is over-built and fuel prices are unpredictable. At those points the market tends to have low marginal costs relative to the average costs. The cost of building, owning, and operating plants is being paid, and the market price looks low.

Then there are other years in which fuel prices are rising rapidly and the market price, marginal cost, is above the price of building, owning, and operating plants. There are cycles of this and nobody can predict when they are, that's part of the problem. At any given point in time, restructuring looks bad or good depending on the relationship between nominal cost and marginal cost. Agitation occurs depending on which system is operating, and which line is higher.

So in the 1990s much of the country had over-built capacity and relatively low gas prices. Being on the market looked good. Wholesale prices in the market were 2 ½ cents, that looked better than the average cost of California electricity. This drove interest in customer choice. Of course there's a further discussion about stranded cost, because units that couldn't make money at this low price.

However, now the marginal cost of electricity tends to be very high, relative to the average cost of building, owning, and operating plants. In the 1990s owning a coal plant looked bad. Now it looks pretty good. There's regret. "Gosh, I wish we hadn't have gone to market-based rates five years ago and allowed recovery of stranded costs for plants that are no longer stranded. I wish we had stuck with the average cost, because it looks better now."

The bigger question should not be where are we in relationship to what stage of the market but rather where do both marginal and nominal cost go from here. The hope is that restructuring reduces costs of both at a moderate level over time, even if the two of them switch with each other. That is how it was supposed to work. Nominal and marginal costs will still cycle with each other because of exogenous factors. The general idea is these lines would be trending down, because somehow the market's becoming more efficient. This occurs over time, it's an extremely slow process, electricity is a very slow industry.

Too often when we focus on retail rate analyses, we miss the bigger picture. Analysis gets focused on the relationship of marginal cost to average cost, rather than a general direction of the two. Certainly Illinois would have been better off if they'd kept the nuclear power plants and coal plants in rate base rather than paying them under market-based pricing now. What do we conclude from that? Does that mean restructuring is always a bad idea? Not necessarily. Maybe with greenhouse gas regulation owning coal plants in the future won't look so good.

This is one of those questions, like many in economics, that don't have a definitive empirical answer. There's a lot of discussion about how we stimulate innovation in new energy technologies and papers that quantitatively examining how policy X gives us innovation Y. They're all hard to believe. This is sort of a religious issue.

If we do try to assess this question, a good way is to study some of the underlying component parts, even if we can't look at the big picture in its entirety. There are a variety of things we can look at. Is productive efficiency better? Are heat rates or employment costs going down? Is the dispatch getting better? Are we using the mix of plants better? Are investment choices somehow getting better?

There are questions about market efficiency. Are prices working properly? Do prices equal short-run MC plus scarcity when there is scarcity? Do capacity markets giving us the right prices for scarcity? There are also questions of competitiveness. One can imagine a result in which efficiencies are being implemented, but not passed on to customers. That's a competition problem. Do prices reflect long-run marginal costs on average? Are prices close to short-run marginal cost plus scarcity?

There is some good work looking at these issues. For instance, Aaron Mansur and Matt White have been looking at the expansion of PJM into neighboring states. They examine whether PJM expansion has increased day ahead net exports from the Midwest to PJM. Literally on the day that PJM expands, the imports dramatically rise. They argue that there are gains from trade that were not being reaped before. Now we see low-cost Midwest imports coming into the more expensive markets.

Catherine Wolfram, Nancy Rose and Kiera Fabrizio have looked at plant efficiency extensively. They find that regulated plants in restructured states tend to cut costs and non-fuel expenses faster than plants in regulated regions. One response to this is that the regulation simply needs to be improved.

Finally, there's a question of how competitive markets are. Borenstein, Bushnell, and Wolak compared hypothetical competitive prices to the actual power exchange prices in California in 2000. The power exchange prices were much higher than they should have been. The qualitative story is that sometimes prices differ from costs by a large amount. Obviously, the question is why they differ so much.

England has had a restructured market for quite some time. From 1995-2005 electricity costs stayed well below inflation, and maintained pace with natural gas costs. About two years ago both electricity and gas shot up. One could argue that this is following the natural costs back up. We might see marginal costs going into one of those upper cycles. Nonetheless, for ten years they enjoyed a significant decline in retail prices. Clearly this is very different from the California data I just discussed. Both situations need extensive analysis before drawing serious conclusions. My takeaway point is that restructuring is not necessarily all bad, and that experiences vary a great deal. We have to be careful about how we're interpreting that question. Analysis that looks at component parts of the market is probably more reliable.

Question: Your chart showed a big blip in the 2000-2001 California PX price. Was that actual prices paid or PX-posted prices? They weren't the same.

Speaker 2: That was the power exchange monthly day-ahead market clearing price. To the extent there forward contracts, or other transactions, it does not reflect the full volume of retail costs occurring.

Question: It wouldn't reflect refunds on settlements or any of the stuff that came after that?

Speaker: No, the analysis occurs before the settlements. Clearly, it's a long-litigated and argued issue.

Speaker 2.

One of the first questions is what choices do we have in mind when we're talking about competition? There's little agreement on terms like restructuring, deregulation, or coordinated markets. They're all different. Coordinated markets and deregulated pricing mean when tight power pools in the east transition from split savings pools to market-based pricing. In the Midwest, and SPP this includes consolidation in the control areas. However, those are completely independent from retail competition and retail choice. You don't have to combine those. I'm going to focus on factors that went into a 2006 research paper by Harvey, McConihe, and Pope.

No one ever thought that New York was going to have retail access. Other issues that came along included open access, pricing problems, competitive processes for procuring power. Every one of these is an independent choice.

Consider a comparison of rates in the Allegheny System in Maryland and West Virginia and how different they are. It has nothing to do with coordinated markets. Both affiliates are part of PJM. They joined the same day. They settle their prices. They all buy power in the wholesale market at market-based rates. This reinforces the variability of prices in ways that have nothing to do with markets.

What are the interesting questions that reasonable people might want to look at. The overall question is the impact on consumer rates from the transition competitive wholesale markets. It's not retail access or competitive procurement programs. It's the implementation of competitive coordinated wholesale markets.

To start one can compare the rates before PJM implemented LMP and after. However, there's a compounding factor. Gas prices are a whole lot higher later. We have to address those factors.

Another approach is to look at a combined model and compare regions with and without coordinated markets. However some of those are fundamentally different. There are rate differences that pre-existed the implementation of coordinated markets. If you look at PJM versus some of the other states, Pennsylvania had higher rates before and after. Any difference in rates isn't attributable to coordinated markets. Conversely, some of the utilities in New York, had much lower rates before and after.

One way to address this is to look at both traditional and coordinated markets before and after and look at how the relationship changed. That's what they decided to do. However, there's another complication. Not all markets are the same in terms of their dependence on gas and oil-fired generation at the margin. In the east a lot of generation is dual-fueled so it's switching back and forth between gas or oil. Some states are much more oil and gas dependent than others. These problems all started in 1972 when oil prices went up. It's what created issues for some of these states historically. This is another complicating factor to hold constant.

Finally, in New York and the original PJM states, the implementation of coordinated markets was coincident with retail choice. Two things happening at once. Researchers would want to focus just on the impact of coordinated markets, not retail access. Especially since retail access discourages long term hedging.

They tried to focus the analysis in three ways, they looked at a sample of public utilities to isolate the effects of retail access. These are entities that don't have retail access. They continue to enter into forward contracts or by generation or whatever they want to hedge the cost for their customers. They can benefit potentially by having access to a spot market and all the other benefits of a coordinated market. The authors tried to control for historic regional gas dependence by splitting the sample between gas dependent and non-gas dependent regions. Finally, they estimated a pooled cross series time series model to control for the historic differences.

What are the results. Rates in eastern PJM, the gas dependent region from '90 to '97, were about \$94 a megawatt hour. Florida, another gas dependent region, had a price just under \$83. An \$11 difference. From '99 to 2004 after implementation of coordinated markets, the difference falls to \$9. The econometric analysis controlled for the characteristics of utilities. They didn't look at just averages, but at the actual dispersion of all the different data points for all the different companies. In essence the introduction of coordinated markets reduced the price difference between the two regions. Certainly, there are lots of other things going on. Its hard to be sure that there aren't other things going on in Florida or PJM. This suggests that there are benefits to the implementation of coordinated markets.

Speaker 3.

An interesting question is to consider the competitiveness of the market over a three year timeframe. I will discuss a paper put out by Harvill that looks at PJM in 2003 prior to PJM expanding, 2004 with ComEd joining, and then 2005 when the rest of PJM as it exists today settled in.

This was to test the hypothesis that given a number of generating units in the industry, the system marginal price would be a decreasing function of the number of owners or generators controlling the units. So as the concentration ratio decreased, one would expect downward pressure on prices to bring them closer to marginal cost. Harvill used a competitive benchmark model based on other research and ran it for those three distinct periods, from May 1st to August 31st. This work was meant to examine FERC policy on standard market design and RTOs.

There were five phases of expansion of the PJM energy market, the four month period from January 1 through April 30 when it was essentially the MAC region, to 11 zones with Allegheny, from May 1 through September 30, then adding Commonwealth Edison. There was a three month period from October to December when American Electric Power in Dayton coming in, and then a fourth phase which integrated Duquesne into the whole system, and then finally when Dominion came in.

Generator market power was a big concern for this type of research. Market power is an ability to profitably raise prices above the competitive levels. The unusual characteristics of the electricity market make those opportunities more viable than in other markets.

There are three types of generator market power. A generator can increase profits by unilaterally withholding units or capacity from the market. It can offer uneconomic bids for certain units that will change the stack of the units. Finally, strategic bidding will also steepen the supply curve.

So PJM had 74,000 megawatts in ’03, just over 100,000 in ’04, and almost 165,000 in ’05. The Hirschmann-Herfindahl Index (HHI) is used to measure concentration ratios in various industries. It was utilized to do a quick evaluation of how concentrated the PJM energy market was as it expanded all three of those years. In all three years, the HHI index fell below the DOJ threshold of a thousand, indicating that the PJM market was reasonably competitive. This doesn’t take into account a number of the idiosyncrasies of the PJM and electricity markets. It does show that market concentration decreased each year as PJM expanded across the United States.

Competitive energy markets need homogenous, divisible output, no interior barriers, full information, supply exceeds demand, no transaction cost, and each firm is competitive or actually acts as a price taker. Under these assumptions, a firm will produce electricity and sell at marginal cost when it is less than or equal to the market price.

The research examined the marginal cost of varying units within PJM. As more units came in, this modified the marginal cost curve or supply curve for each of the years. Marginal cost was defined by the heat rate times the fuel cost controlled for the cost of emissions and variable O & M expenses for each of the units. On the supply side, forced outages were accounted for, along the lines of research done by Bushnell.

An aggregate supply curve was constructed. Price was determined based on the marginal cost of the most expensive unit. For each hour of every day during the period in question, an aggregate supply curve was created and compared to the actual aggregate demand curve for that particular hour.

On the demand side ancillary services, hydro generation, and imports were all accounted for. The hydro is an important factor in the analysis. LMP takes into account price, congestion and losses. The original goal of the analysis was to look at the PJM energy market during unconstrained hours. At that time, all the prices at the different nodes are the same and congestion really isn’t a factor. However, when Commonwealth Edison joined in 2004 without other utilities touching PJM, it sent congestion through the roof. This made the analysis impossible to do at that particular point.

Instead, they just looked at the market during all hours. The data was cut many different ways and the results are still the same for the most part. For the time period in question, the market performance reflected price mark-ups over marginal cost for each of the periods. So in May of 2003, prices were about 35% above the underlying competitive marginal cost according to the simulation. In June, they were actually negative. In August they were around 4%. For the 4 month period in 2003, prices were around 6.5% over marginal cost on average.

For 2004, markups were just over 5% for 2004. In 2005, average price markups were around 0%. Both ’04 and ’05 had similar patterns with large markups in May, and much smaller markups that were occasionally negative in the other three months.

One question is why were there negative markups? There were a number of hours within the simulation with negative markups For the most part unit commitment constraints were largely to account for negative markups. These include start up costs, ramping of rates, minimum down times and such. All the kinds of things that MIP can solve incidentally.

Market Power is measured most commonly as a load-weighted Lerner index. This compares expected marginal price and actual price. As the market increased in size, the Lerner index decreased from 6.44% to -0.52%. The other notable, but relatively obvious, finding was that when Commonwealth Edison joined it created a lot of congestion on the system. This was fixed in 2005 when AEP joined and created a link to the east.

Negative measurements occur because the modeling can't account for unit commitment constraints such as ramp times, start-up costs, and minimum down times. These adjustments are inter-temporal in nature.

The most important aspect of the research is that it confirms that as the market becomes larger and less concentrated, there is downward pressure on prices. It validates the FERC position on standard market design. Moving more companies into competitive markets has a strong impact on prices.

Speaker 1: In May months there is a fairly consistent 30-35% increase in market power. Why? Are the units off for maintenance?

Speaker 3: I think that could be part of it. Further analysis is still needed to confirm that though.

Speaker 4.

The other three panelists focused on wholesale issues, I will address retail. I'm going to focus on a comprehensive report done for the Virginia State Corporation Commission on restructuring and retail access. I'll also update some of that material. Virginia has since repealed their law but the report is posted on the website of the Institute of Public Utilities at Michigan State.

Early assessments looked at the percent of customer load switching. It's an indication of how healthy the markets were. However, it's not very interesting, and for some states there really wasn't a lot of activity going on anyhow. License numbers of suppliers were also examined to get a sense of market activity but this was also not helpful. Looking at competitor prices was a promising avenue. For instance Pennsylvania in 1999 had around 25 competitive offers for customers in the PECO territory fairly. That's a lot of data to look at but it wasn't sustained. One approach is to look at aggregated data from DOE and EIA on a state by state basis for the entire country. Another way is to look at changes in the standard offers of prices. A lot of that analysis is in the Virginia report.

Information on the market share of suppliers would be very helpful but that's kept confidential in many states. You don't know how much a competitive affiliate of the utility is taking market shares specifically at those shopping numbers.

Let's consider the DOE aggregated data. About 13 states still have retail access now, we lost Virginia recently. Mostly in the northeast, a few in the mid-west, and Texas. Michigan and Arizona have retail access for all customers but they still regulate the generation price – this is a relatively unknown hybrid model. There are three states that have limited access for large customers. Retail access has been suspended across California. Yeah, California is very special. [laughter] Montana has a unique situation where access is bifurcated at 5 MW with opt-ins for small customers, and four other states have delayed retail access. Finally there are 26 with no plans for retail access.

Let's consider the percent change in prices from 2002 to 2006. In the northeast, mid-Atlantic, and Texas have very sizeable increases – some over 50%. Generally, price increases are higher in states with retail access. Remember however that it's not always the entire state. You still have municipal suppliers, coops and sometimes it's phased in too, even by investor owned utilities. It's important to distinguish between a restructured state versus a state with truly market driven prices.

Connecticut, Massachusetts, and Texas are really doing the worst. New Jersey and Maine are the two that have had the most success moderating their prices. From 1990, there is a sizable difference between regulated and restructured states. Clearly the states that restructured did so because their prices were higher.

In the late '90s, when restructuring laws went into effect, there was usually a discount during the transition period. Illinois was probably one of the more dramatic ones. They had a 20% discount. This kept it flat for almost the entire period and then in 2007 they saw a jump up that put them back to about the national average. The discounts varied in duration, from 4 to 10 years. Places where the caps have expired are clearly increasing at a faster rate than the national average, or regulated states.

Other folks have done slightly different analyses; Marilyn Showalter, and an EEI funded study by the Brattle Group. The Brattle report looks at all the restructured states without differentiating between states that still have discounts or transitions in effect and those that don't. When the analysis is done this way, it averages out so that there seems to be little difference between approach in the states. You really need to assess those that are really in the market right now. In the four year period regulated states went up about 20% and market based retail states went up about 35%.

This approach is imperfect however. It's better to do state by state comparisons or regional comparisons that better account for big differences in fuel use profiles. Alternately, the restructured states have considerable portions of their markets like Munis and Coops which don't participate in retail access and their rates, probably cheaper, dampen the price increases in some of the retail access states. For example, in Texas, if you just looked the five big utilities, the percentage increase would actually be higher if Texas' Munis and Coops were not included. The variation between utilities offering retail access also doesn't show up in aggregate analysis. In one the price is going up and the other going down and it washes out. The EIA data is always 1.5 years later, and doesn't include company level data. There are also consistency problems for certain customer groups, i.e. industrials, that are measured differently in different states.

A second useful way to analyze this problem is to compare the retail price with the wholesale price for energy capacity, and include all components that go into a customer's price. This came out of work in Illinois examining their auctions and trying to benchmark against the wholesale market to determine if the auction prices were any good. This approach takes the wholesale price as a given and just sizes up the retail market, and may provide a better analysis of competitive retail prices.

This analysis looked at the 2006 auctions in five states: Virginia, Delaware, Maryland, New Jersey and Pennsylvania. They were all in PJM except Pike County which was in the New York area. They were all around $100 per megawatt hour. Similar analysis was done in Illinois. The Illinois auction price was lower, about $65. It didn't vary much by length of time, 1-3 years the price was about the same. The average PJM wholesale price was about $48. That's just northern Illinois in 2006.

So what makes up the difference? Besides energy there's quite a few things. The first five or so are fairly quantifiable in a reasonable way: capacity, ancillary services, congestion charges or FTR costs, transmission and RTO administrative costs, and load change or "load following" risk such as weather or general economy effects. However suppliers also mentioned the following costs such as customer migration risk, fuel price change risk, administrative and legal costs, regulatory/legislative change risk, and utility "counterparty" credit risk.

Everything in Illinois was so contentious that folks could not agree on any of those values. Energy should be fairly straightforward but some wanted to use PJM data, others wanted Platt's data, somebody else wanted the forward and Nymex price. The risk management one is not so quantifiable but the congestion is, but capacity you can use now the RPM. However there were difficulties because of the Ameren companies in the rest of Illinois. Same thing for ancillary services; there's a market or a flat price with estimated costs. As you go down the list, the ability to quantify the costs gets more and more difficult. After those first five items, there's still $15 or so in price difference between the auction price and the wholesale that can't be explained. The suppliers argue that the other $15 is taken up by other risk costs and legal/admin costs. Ultimately, it becomes impossible to measure in an objective manner. Some of these costs didn't exist under the regulatory regime.

They are relatively new, and that makes quantifying them even one step more difficult.

So what's the answer? Well, the paragraph describing this panel had some very interesting questions but considering it took be 15 minutes just to read it, I didn't think I could answer it in 15 minutes [LAUGHTER]. Seriously, there are some very good questions in there. I want to address whether it's possible or not to actually assess the performance of the market.

A couple of conclusions. So far, EIA data shows residential customers in market states have higher price rises than regulated states. Yes, both are going up, and the market states clearly started out higher. Clearly, price increases are higher in market states for residential retail.

Second, in the benchmark component analysis, there are more component costs for competitive suppliers than for vertically integrated companies. Vertical economies were lost when utilities were unbundled. Most assumed, including myself, that those losses would be off-set by transmission scale economies and other cost savers from technology or even the MIP implementation discussed last session. However, I'm not sure the offsets are big enough when some of those are examined. Although we may be saving money in terms of the scale economies of large RTOs, we may be seeing increased costs right back in on the retail side. Some of those costs were lower, or didn't exist previously. Customer migration risks are new, and regulatory, legislative, legal, administrative, and credit risks may be higher in a competitive retail regime. Nonetheless, we clearly need more data, a longer time period of study, and a longer implementation of markets in retail to get a complete sense of it all.

Question: In your data there was about a $50 per megawatt hour difference in the eastern part of PJM, and a $17 per megawatt difference in Illinois. In Illinois you mentioned that there was about $15 unaccounted for. Was that $15 the same in the eastern auctions as in Illinois or did that vary?

Speaker 4: Most of the difference is energy and other costs like ancillary service capacity. When you convert capacity into dollars per megawatt hour, it's not very much.

Question: Some argue that competition works relatively better when gas prices are lower. Regulation works better when high price gas provides a surplus for all the other sources of electricity. What is your reaction to that argument?

Speaker 1: That's a specific manifestation of the cycles I was discussing in my presentation. We know of the large run up in natural gas prices and it is the marginal fuel in almost all of the country. The amount of money needed for this market clearing price is greater than money needed for building, owning and operating alternative plants. It depends on high gas prices but also the cost of operating alternate plants, too. Your argument makes implicit sense. It doesn't mean it's going to stay that way. Even if gas prices rise, other costs could rise higher and change the cycle. The overall idea of restructuring is that both sets of costs would trend down in the long run but the relationship at any given moment in time between that marginal cost and the average cost sometimes is arbitrary.

Speaker 4: There is a lot of variation in the gas being used. In PJM 90% of the generation was nuclear and coal last year. Gas being on the margin sets the price. Under a regulated regime, the price would have been based on the average. When you go to the market, marginal cost affects that price, not the average.

Speaker 3: I think of it differently. It's a matter of hedging. If folks had contracted for 10 years of power, then they wouldn't be facing marginal gas prices today. In a regulated utility, the contracts are power for a lot of years; the hedging is incorporated into the model. If retail access customers wanted to do that, and big industrials could, they could also do that and pay what gas prices were from '90 to the present.

The designs of retail access programs for residential customers are structured to push people into the spot market. It's volatile, and pricey sometimes. Hedging, at least to some degree would considerably reduce that.

Question: These assessments get clouded in terms of the valuation of legacy assets. Many states went to market without long term vesting contracts on legacy assets. Has anyone done research that addresses this question? It would really improve our understanding and the valuation of market efficiencies. It would also sort out the concern for some of the diseconomies lost in the lack of vertical integration.

Speaker 1: I haven't seen any of this. There are several issues. Stranded cost recovery is a form of legacy contract. Some of those were one sided in the sense that generation got their money back and then when the market turned, there wasn't any concurrent hedge of the market position that customers benefited from.

Question: If we did stranded cost recovery with an after the fact true up or accounting, it would be similar to having a vesting contract.

Speaker 1: In regions that want to re-regulate and get those assets again, it turns out they are much more expensive than they used to be. Outside of the U.S. there were vesting contracts that were more explicit and tied revenues to the market price and the value of the plant. If everybody in the market had known where gas prices were going to go when these assets were divested, the added value of those assets would have been accounted for in the sale price and there wouldn't have been any stranded asset recovery to worry about. It would be an interesting approach.

Speaker 4: Unfortunately, there's no cross sectional way of looking at that now because the assets are outside the state commission jurisdiction in most states with market prices. They've been sold or transferred to a competitive affiliate. Most of the investor owned assets are gone, or nearly all.

Speaker 3: Most are struggling with the timing of the issue. The marginal cost curve is above the average cost curve. Strangely, there are two states where the market rate is starting to fall below their regulated rate. They're now considering competition. Nonetheless, for the most part we haven't heard that discussion taking place for the past several years once market prices started going up and politics are interjected into the process.

Question: The presentations today and other research suggest restructuring benefits come from production and dispatch efficiencies. Is it possible that it wasn't that regulation failed, but rather that certain areas of the country had just too many utilities? Thus, they were losing out on a lot of the scope and scale of being able to dispatch over a region or a wider range. Would consolidation of the industry have lead to greater efficiencies without many of the costs that of restructuring, particularly the costs of forming RTOs? Second, if you are in a region where utilities are already as large as RTOs, is restructuring necessary?

Speaker 4: A consolidation with regulation model. A lot of those economies of scale and transmission from dispatching over a wide geographic area could be captured by a consolidation just in the transmission, not necessarily even consolidation into one big company.

Speaker 2: A lot of the coordination benefits come from coordinating the transmission system over a large area. If all the PJM utilities were consolidated into one entity with one software, and one unit commitment problem. It would be more complicated because you have lots of units and transmission. You'd still have spend more money on software, but you get the benefits.

Unfortunately, back then and probably now, FERC would not let you start that conversation. There were other benefits like an open spot market for IPP generation and qualified facilities. In New York because there is a spot market people want to and are able to negotiate their way out of contracts. They'd rather be in the spot market because its not run by the regulated utility, its run as a competitive market by an independent entity.

There were certainly benefits in terms of a wholesale market and benefits and regrets concerning divestitures. For instance, nuclear plants that weren't run well as vertically integrated utilities. Now they are owned by companies that are good at running nuclear plants. They have performance incentives that get them the money in the spot market if they run the plant well and keep it online. Spot market pricing provides a tool that regulators can use to provide more incentives for utilities to perform well. I'm not sure the incentives could work similarly if the vertically integrated utility was running the system operator.

New York implemented a program to provide performance incentives for transmission owner maintenance based on the cost of the outages and allocating it back to the transmission owner. That's acceptable to the PSC and the regulators because its done by an independent entity. A vertically integrated utility could not reward itself for its performance similarly. There are potential benefits in each scenario.

Question: Which data should we look at? Do we look at retail prices ultimately or compartmentalize things and look at the wholesale market? These questions and studies can deliver insights, but electricity only has value if its used by an end user and they are deriving a benefit. If we show efficiencies but people are paying more for that efficiency then it may not actually be an efficiency.

The retail system informs the wholesale system, retail prices are the combination of a wholesale and retail structure. Consider an RTO made up entirely of regulated states and regulated utilities. There would be captive customers with utilities that do long term contracts and put generation in place and have eminent domain for transmission. I resist the idea that you can look at these things separately. It's not bad to look at them analytically at some point but when making the total evaluation, we have to add it up. Consider principles in the regulatory world. In a rate case to determine a revenue requirement, they add up all the plants, cars, poles, and the employees, etc. but at some point the courts say they one has to step back and look at the whole thing and ask is this working? The value of looking empirically at prices, not underlying theoretical mechanisms, is really the best way. That's the only way to judge consumer benefit.

Second, the timing cycle issue and whether competition would be good if natural gas prices hadn't gone up. The test of a market design is when it's stressed, not when times are good. It doesn't say much that competition would have worked if natural gas prices hadn't gone up. You need to test it over the long term. One could argue that competition that contributed to increased natural gas prices because it forced a short-run mentality and a lot of gas plants were built.

Finally, I don't see marginal prices or costs going down. We just heard about two states were that may be the case. When we consider the tightening of world energy supply and global warming imperatives, the foreseeable future will have marginal bids above marginal cost and average cost. Existing plants will continue to make a lot of money that is not required to be put back into the system. That's probably where some of the $15 difference is.

Speaker 1: The market simulation models I discussed looked at various heat rates or various units within PJM. They looked at the specific fuel cost for each of those units based upon the type of fuel that they actually burn. The emission costs on a daily basis and empirically-derived O&M expenses for various types of units.

I have a different perspective as an advocate of competition. Everything we've heard about today has been about price but there are other factors like innovation, production or dispatch efficiencies.

For instance, Illinois' regulated nuclear units didn't operate very well or very often. It was a substantial problem. The efficiency of those units in a competitive regime is completely different.

Second, the counterfactual of whether prices would have been lower had we stayed with regulation is very hard to determine. The assumptions that underlie the original decision have all completely changed.

There's an innovation perspective too. In retail customers get different products and services far beyond the regulated environment. Retail vendors have 17 or 18 different products for C&I in some markets. Those innovations can create real cost savings for the buyers that don't get quantified in the price equation. Generally, the trend is positive – it's not perfect results, but over the long term that trend will continue and it will ultimately provide benefits in the form of price to consumers.

Speaker 1: I agree that retail rates are probably the most important number to look at in the end. However we should also use that as the starting point to dig deeper and understand why prices are what they are in different regions of the country.

Restructuring does have all these facets and some are working better than others. Gaining an understanding of the component parts can improve the restructuring model. With greenhouse gas legislation we may see coal on the margin once again and the model will look different. It's very hard to predict the future in that relationship.

If regulation is better, then we may be better off keeping owned assets under cost-of-service regulation, although some efficiencies may be lost. However, there are also other incentives for new construction that benefit from production or coordination. If the benefits are investment incentives, can one capture the benefits of new investment without giving away the rents from good assets that we already like and own. This probably requires an ISO, and raises questions about capacity markets.

We need to be very careful when looking at retail rate changes over the last ten years. The analysis needs to be done very carefully. I'm the ultimate equivocator. I have not yet decided. California hasn't benefited from restructuring. It would have been better off if they had stuck under cost-of-service. Other parts of the world have really benefited from competition so it's a more complicated question.

Speaker 4: Retail prices are the acid test. The intense rate increases in the last couple years are not a lot of fun in those states. Legislators don't care about the subtleties of what's on the margin. Still, I'd like to probe a bit deeper for the underlying causes.

Speaker 2: One should absolutely examine whether the benefits filter through in retail rates. In the analysis I discussed, the spread between PJM and Florida decreased despite the high gas prices. That analysis shows that competition works when gas prices are low or high.

A lot of this is about hedging. If a regulated company decided to buy all the power in the spot market in 2005, and they had no generation, that would be a high-cost strategy. If an unbundled state had retail access customers who went out and contracted for power for ten years in 2003, it would be cheap and they would look like geniuses.

It's not regulation or not, it's whether participants lock in prices. A vertically-integrated utility with a mixture of nuclear, coal, and gas-fired generation can be thought of as having a forward contract hedge. There were enormous problems in Eastern states and residential customers had to pay enormous costs under regulation that they should not have had to pay. So it's hard; there are no easy answers.

Question: We've heard that when marginal cost is below average cost, people want marginal cost, when those flip, then they want the other. However this analysis of competition in the past has limited value as we face the future. There are different challenges ahead like the volume and type of investment. What can this research do to guide us going forward as decisions on half a trillion dollars worth of generation investment in the next five to ten years are made?

Speaker 4: That's a huge problem. Especially with carbon limitations. One way to approach it is to ask which model is better at encouraging investment. Regulation encouraged overinvestment and gold plating in the past and restructuring seems to create under-investment, at least in large baseload capacity.

Some utilities have suggested they're willing to build under long-term contract arrangement or something that looks like cost-based regulation. Some states might be building capacity too; Illinois, Connecticut and Delaware. That remains to be seen.

Nuclear power is incredibly controversial. How is that going to get built? Can somebody do that?

Speaker 3: This research doesn't give us a conclusive answer. There are some components that have worked better than others, but not one system over another. I am inclined towards a structure where you have BGS style auctions like New Jersey's. It solves the long-term contracting problems in the markets, and provides security for merchants who fear they will be undercut by publically funded investments.

Long-term contracts are imperative. Is there a market failure that prevents this? If so, some of the eastern procurement models seem to help, with modifications. Acquiring a strict percentage of any load shape puts risk on a supplier that's not worth the cost. So let's just buy fixed amounts of megawatt hours instead of buying percentages of demand. We need more experimentation of these models in the east to determine what's best.

Finally we have to address the reality of large distribution companies buying power from the wholesale market. It's not retail choice or vertical integration, it's how to make large distribution purchases of wholesale power work. The BGS auction is a conceptually good compromise.

Comment: Microeconomics says that pricing things at marginal cost has enormous societal benefits. When it isn't, there's problems in terms of incentivizing investment and providing appropriate products for consumers. Is there something about electricity? It's now the only product in our entire economy that is not priced at marginal cost.

Speaker 3: The old thinking was that marginal cost was below average cost, because of economies of scale. In regulatory economics, they would draw an average cost curve over the output range and then show marginal cost as falling too. So if one was to charge marginal cost, businesses couldn't cover capital costs. Then economists saw data in the '70s and '80s, the average costs were rising, and therefore the marginal costs were rising, and higher than the average cost.

It depends on where you think you are. If there are still economies of scale, one can argue that average cost might be the better way to go. That gets at this question about customers always wanting the lower of the marginal or the average cost.

I don't completely buy the argument that marginal costs were low in the '90s. There was something else going that was hard to recognize. Industrial customers saw $15 dollar power and wanted in. That was not the marginal cost of power. That was the cost of energy only. The capital costs were being collected from the rate payers in that state. It's not the right comparison. That's a rationale to consider.

Speaker 1: Prices in the western United States were heavily influenced by a lot of other things. Marginal costs may not have been up to the 11 cents that we were seeing as some of the costs of some of the generation here. Retail rates here have a lot of other stuff in it other than energy. A lot of that is still a natural monopoly, you can't really charge marginal cost for it.

With electricity, customers can't respond to marginal cost. One of the big benefits of charging marginal cost is efficient consumption, but that hasn't been implemented. It can't work without demand being a real component of pricing.

Speaker 2: There are benefits for marginal cost pricing, we need it. Demand response and reduced consumption are also going to be needed, particularly with GHG. Consumers need to value electricity the same way they consumer it. We need marginal cost pricing from that perspective.

However, average cost is not less than marginal cost. The average cost of new plants is higher than the current marginal cost. People who are building new plants want the state to help them out and subsidize it. There are state subsidies in financing for some regulated utilities in recent investments.

Simply, it's good to have an old plant that was built before that you bought cheap and to have entered into a long-term contract ten years ago. So I think we still want to price at a marginal cost to make sure that we only consume the power we need, that we don't build capacity that we don't need on peak if someone else will reduce their consumption. And I think the trend in most states is to try to get more demand response, which means more response to the high marginal cost of the power when it's high.

Speaker 3: It's true, we've dealt with half of the equation here. Demand is the key here. Even today, ten years into restructuring, the vast majority of people in the United States still don't see the real prices of the commodity they're consuming; they're seeing an average price. They don't respond to it. That price signal is critical for both regulated and market systems.

Question: I'm reminded of two stories. Henry Kissinger when he was meeting with Zhou Enlai in China asked him what he thought about the outcome of the French Revolution, and the answer was, "too early to tell." [laughter] The second one is when Larry Ruff came back from the UK after they started restructuring and people in the U.S. asked him, how is it working? He says, "it's working just like it was supposed to: costs are down and prices are up." [laughter]

The earlier point that overall price assessment is most important is correct. However, it's a mistake to assume that retail prices before were appropriate. If prices haven't gone down more than they went down before, that this is a failure. It could be entirely that retail prices before were misaligned and now it's a more efficient outcome.

The two stories I gave demonstrate that the real core of the issue is not operating efficiencies, which are impressive, but rather investment decisions. It's going to take a long time for those to unfold. Sadly, it's a comparison between investment decisions under imperfect regulation compared to investment decisions under imperfect markets. That's what makes it interesting. Constructing the counterfactual over a long period of time should focus on whether decisions and investments in either market are better or worse. This is enormously hard to compare, especially over a long period. I'll take your comments.

Speaker 2: A precise empirical study is not possible. Anecdotal studies seem to be a substitute. They can be useful if used very carefully. Further, there's a wide variety of how we incentivize investments across different restructured markets. There's a question of how resource adequacy policies interact with investment decisions as well. There's no controlled experiment but rather seven different models all coexisting simultaneously.

Speaker 3: Many market states started out high. So they did restructuring in the hope that things would improve. If rates were not leading to the best outcome for the customers, they started out with high prices and now they're going higher. It's a shocking development. I was a supporter of the idea and it's gone in the opposite direction. Add to this the lack of incentive for large investment. That's going to be the problem that we're going to live with for a long time.

Speaker 4: This discussion in 2003 or 2004 would be completely different; focused on expanding the competitive footprint throughout the U.S. Prices in the Midwest were hovering around $30 dollars. The price run-up is fairly recent. The timing matters.

In the past the consumers bore all the risk of the investment and regulatory decisions. Now the risk has been shifted – that's a burden that hasn't been implemented in the cost analysis. The costs of the bad gas plant investment decisions have been absorbed by the people who made those decisions, not the public.

Building new generation takes a long time. Coal or nuclear, it's 5-15 years. Recent reliability reports show there's been little need for new capacity in the United States. There haven't been a lot of investment decisions, there will be in the next few years. This is a relatively new issue. Nonetheless, the risk will not be on the consumers.

Question: The FERC is discussing LMPs a lot because several interveners have argued that LMPs cause all kinds of problems. In the UK they don't use them at all. It looks like their prices have gone up despite the fact that they don't have LMP. It looks like they're chasing the natural gas price with a slight lag, depending on how you do the indexing.

Second, some of the other data shown on auction prices and the LMPs seem to indicate that unless one is a retail customer that is deathly afraid of a price spike, they're better off just buying at the locational marginal price.

Speaker 2: I will answer the question of whether one would be better off buying on the spot market and getting other components? Or perhaps bilateral arrangements that mix and match different components. The original analysis was meant to determine if this would be better than the auction process. There's not an obvious conclusion. One can buy energy below the auction price, and the other components, and it would probably minimize price. So if Illinois as a state were to go out and buy power on the spot market, what would happen? One big buyer like that would be a problem obviously, the price would go up.

Question: A bilateral market?

Speaker 2: Either the spot or the bilateral. It would almost certainly have some effect because they'd be so massive.

Question: But they're only buying power that is already going to be bought.

Speaker 2: Yes, it's the same kilowatt hours but it gets sliced and diced differently.

Speaker 3: I'm familiar with the Illinois auctions, they were truly competitive. There were big players like Constellation, Exelon, Amersen, Goldman-Sachs. It truly reflected risks that those players saw in the market. Further, that price would have been very similar to a competitive RFP process run by the state.

Speaker 1: I'll discuss the UK situation. It's been a big surprise because of the previous large decline and then this really big run-up. All without LMP. I'm not sure what to make of it.

The Illinois question suggests that the design of the wholesale market might be creating new risks, or that things are getting priced properly and explicitly that weren't getting addressed previously. The instruments in these auctions seem designed to eliminate all risk for the distribution company. Whatever demand is, the seller has to meet it.

Is this 100% quantity insurance the sweet spot on the price/risk management tradeoff curve? I suspect not. It would be great to see data on side by side fixed quantity versus slice of load auctions. Normally one associates lower capital costs of certain types of entities or savings as an underlying shifting of risk. New investment may be higher because there's little or no guarantee of ex-post recovery if things go against them.

Question: With investment, a number of regulated utilities will be almost doubling retail rates in the future because of the need to make investment in their power systems. I hear from other regulated utilities that they haven't had a rate case in ten years, they have not rolled any new investment back to the customer.

Many of these utilities are living off investments that were made perhaps irrationally or unproductively during the building boom. Now that value is flowing to the regulated rate payer at very low cost. Some generating units were bought at 30 cents on the dollar or less. Some generation was far less than could have been built under a regulated regime. In these various studies, have these cross-subsidy type benefits coming from the deregulated environment or the actions prompted by deregulation been factored in?

Speaker 3: No. Neither in the case of states that did restructure, those assets are legacy also. They're collecting economic rent selling power where the capital costs were paid for by the rate payers and now they're just facing operating costs. It cuts both ways.

I'm not convinced that we'll see a one-sided increase in rates. Investments are needed all over the country. I expect higher prices throughout.

There are two regulated states with very high rates. This is almost entirely because of investment in generation and transmission. Wisconsin with transmission and Florida because of its growth and generation building. It will affect all kinds of states.

Speaker 4: Florida and the cost of new investments reinforces a comment I made earlier. The problem isn't that average cost is lower than marginal cost, because if it were lower, then building new plants wouldn't drive rates so much. The point is that old investments are cheap and new investments have average costs that are extremely high too. Florida is also strongly affected by gas. They're just like PJM or New York, it's like 30% or 40%.

Question: There's two easy lessons from this session. Rate freezes are stupid. So is buying only in a spot market without any sort of forward hedge. On a different note, why isn't the past informative of what we face in the future with respect to risk and innovation?

What about the assets we like? For instance there are a lot of recent nuclear proponents. Part of restructuring was driven by the fact that fuel choice was part of the equation. PURPA, a surrogate for competition, showed that the state wasn't any better at determining the future cost of electricity. That's when the industry moved to auctions. It was the competitive features of auctions that commercialized combined-cycle turbine technology, the heat rates mattered.

Now California has about 15,000 megawatts of new generation, most of it combined-cycle. Most of that came from the market before it disintegrated. It came from market-based investment decisions. In the upcoming global climate change debate it is unlikely that regulators will handle risk or innovation any better than they did in the past.

Speaker 3: In the 90s it looked like there was cheap power available but it really wasn't. There was cheap energy that could be purchased but only because others had paid for it. It was not the marginal cost of power that was available at that time. It's great that we were able to build a lot of new capacity and combined-cycle. However it's expensive, at best intermediate, mostly peak, and fuel diversity suffered.

There's less sulfur dioxide, but there's still carbon going into the atmosphere. Gas does emit carbon dioxide, albeit more efficiently.

I don't know how to fix the risk. There's not enough capacity, but we don't know how to address carbon. Long-term contracting and regulation bring us back to past problems. There are significant issues in both systems.

Speaker 2: It's a good reminder to look at 1982 to 1995 as well as '96 through 2004. It could be that the cost of building, owning and operating new power plants is pretty unpleasant relative to the market price of power. It depends on how tight the market gets as to what the marginal cost ends up being. Going forward what do we do? Those economics are captured by looking at the rates, but also the embedded cost pricing. We should look at history but with rates it's a cloudy history. We have to look very carefully.

Question: These studies provide some guidance for the future. In this country, people get used to consuming a certain amount of energy. They don't immediately go out and buy a Prius. They're still driving their Suburban or using their low-efficiency air conditioner. The timing is everything. We saw a comparison on price rises between regulated and deregulated states from 2002 to 2007. That's the competitive model under stress. Others would say let's test the regulated model when demand goes down and price goes up. With all that, if we re-regulated, what would the prices be? That's the ultimate question.

Speaker 2: Most states have said it's too late, it would involve re-purchasing the assets at market value. It seems unproductive. Areas that have not made a decision and for them the question is critical.

Speaker 3: The lesson from restructuring is careful what you wish for. Montana is the only state that tried to go back. They repealed retail access but they're still buying power on the market for their customers because the utility doesn't exist anymore and the assets are now owned by an independent entity. They weren't able to go back. Virginia, never let the generation go and has made some bad decisions along the way. They ceded their authority to set the rate of return based on the rate of return of what was determined in all the other states in the Southeast. There's no oversight for the public interest there.

Speaker 2: If I look at '90 to 2007, it was closer, the high-priced states hadn't gone up quite as much as the other ones. Is that correct?

Speaker 4: Well even if it's the same, how come they're not getting the savings? Now the question is why are they going up faster?

Speaker 2: Michigan, Ohio, and Pennsylvania are all considering the idea of re-regulation. If they haven't divested fully they may be able to go back. In ten more years we'll get to have the stranded costs debate, again. I'm not sure shifting that risk to consumers is going to be in the best interest of those consumers.

Speaker 4: There are 30 states that are still regulated. It's a natural experiment in the Brandeis tradition of states as laboratories. We'll get to watch them all over the next 30 years and really be able to analyze the prices over the long term.

Session Three.
Allocating Carbon Emission Allowances: Who Gets What and How?

If there is to be a cap and trade regime for carbon emissions, there will inevitably be a contentious debate over the initial allocation of allowances. How should the allowances be allocated? Should it be based on existing levels of carbon emissions? If so does that unfairly "reward heavy polluters?" Conversely, how can it be assured that the allowances are allocated to plants in ways that incentivize their most efficient use? Is an auction, or other market mechanism a more efficient way of allocating allowances? How should such a mechanism be designed to assure the most economically efficient use and most desirable environmental result?

To the extent that funds are derived from an auction or other such mechanism, what should be done with the revenues derived? Should they be earmarked for carbon related expenditures such as R&D or commercializing innovative technology, or even compliance enforcement and monitoring, or should they simply go into the general treasury, or perhaps even be rebated to consumers? How should regulators treat the allowances? Are they investors' assets or do they belong to ratepayers and the utilities hold and use them in a fiduciary capacity? Should, for regulatory purposes, allowances be treated differently from regulated generation than they are for unregulated plants? What are the effects of treating regulated and unregulated plants differently?

Moderator: Just yesterday there was a historic moment in the Senate, when the Natural Resources Committee passed the first climate change legislation in the nation's history. This is just the beginning though. There is growing consensus that cap and trade is the best way to achieve reductions at the lowest economic cost. Cap and trade requires the establishment of permits to emit greenhouse gases with the number of permits declining each year, until the desired results are achieved.

How the permits are made available is a multi-billion dollar decision. There's two general options, and many proposals have some combination of the two. The first, which is the one favored by most economists is to auction the permits, making them available to the highest bidder as long as they are available. But auctions create federal revenues, and what to do with those revenues becomes a contentious issue. The second option, is to provide the permits at no cost to emitters, based on historical criteria. Providing permits to emitters reduces the cost that those entities would otherwise have to pay to meet emission limitations.

Speaker 1.

I will focus on cost and the distributional implications of the cap and trade system. It's useful to compare the value of allowances that would be used in that sector with the value of other major inputs to electricity generation. Let's examine recent analysis by the EIA of the McCain-Lieberman Act. EIA's projections for 2020 puts the total delivered value of coal at $30 billion a year and natural gas at $40 billion. By comparison the total value of CO2 allowance in the electricity sector is $47 billion. Clearly the allocation decisions will have substantial distributional consequences and impacts on the aggregate cost of the cap and trade system. That's a societal cost, as opposed to the cost to any individual firm. While individual firms might incur costs associated with purchasing allowance, that cost is offset by the revenue that whoever initially held the allowance receives from the sale of the allowance. So again, it's not the value of these allowances, but rather how they're distributed.

The allocation decision has two components. The first is whether allowances will be auctioned versus freely allocated. There's no need to choose either 100% auction or 100% free allocation. That percentage can be somewhere in between, and can vary over time. Second, if they distribute allowances for free, how will they be distributed. There are a lot of options in these decisions. There's been some historical precedent about how to allocate allowances in the SO2 program that only allocates to those that are directly regulated. However, they can go to many entities, including those that are not directly regulated under the cap and trade system. The reason is that under a cap and trade system for CO2, the cost of these allowances will be widely spread throughout the economy. There's no prior reason to suggest that allocation should only go to those who are required to surrender allowances. Second, there's no need for allowances to go to particular entities in order for that market to function well. As long as there is a liquid allowance market, regardless of how they're initially distributed, they will end up in the hands of those that value them the most.

One debate is whether fossil fuel suppliers or emitters be the ones responsible for surrendering allowances. Ultimately, this will not affect the functioning of the market. There's no correct approach to allocating allowances, either in terms of making sure that the market functions appropriately or on distributional grounds. The optimal approach really should satisfy policy objectives, not distributional squabbles.

That being said, the cost implications will certainly be strongly discussed. The choice between auctions or allocations will have significant consequences for the overall cost of a cap and trade system. Auctions have been favored as a less socially costly means of allocating allowances. Auctioning creates a potential pool of revenue that can be recycled into the economy. Doing so reduces distortionary taxes and can create economic gains that offset some of the costs of the climate policy. Second, if one allocates freely to regulated utilities it's possible the savings will be passed on to consumers, and they won't face the full price of carbon in their electricity rates. If so, they lose some of the cost incentives to reduce consumption; they're not facing the full price of carbon in their electricity rates.

There are two caveats to these arguments. The gains from revenue recycling of auction revenue depend on tying tax reform to climate policy. That may be very hard to do. The type of tax reform that maximizes gains and reduces the cost of a cap and trade system would be particularly regressive tax reform. The studies that highlight these benefits focus on reducing for instance corporate income tax or the personal income tax rates of the highest income brackets. Those are already viewed as some of the most economically distortionary taxes in the economy. Further, one can do this without auctioning allowances. It's perfectly feasible to reform the tax code without using auction revenue. Obviously auction revenue may grease the wheels a little bit by providing an additional revenue to facilitate that tax reform. It's not necessary to auction allowances in order to make sure that consumers face the full price of carbon. Utilities or regulators can set their rates so that consumers face the full price of carbon regardless. Auctioning will increase the burdens on utilities and force automatic rate increases.

There's an opportunity cost associated with allocation allowances. Allowances can create economic gain. Second, allocations may affect the incentives under a cap and trade system for particular emission reductions. The method of allocations, and the choice of how many to allocate is critical. Cap and Trade provides a consistent incentive to reduce all emissions that can be reduced at a cost less than the price of that allowance.

Some approaches will have no influence on the incentives for reducing emissions. For example, allocating based on historical output or historical emissions. Entities can't influence their historical output in emissions, they can't change history. Historical allocations will not influence ongoing production decisions. Alternately, allocation methods that fix allowance distribution at the outset of a program will have an effect. "Updating," or conditional allocation dependent on firms' or recipients' future production decisions will have a different effect. For example, giving free allowances to new entrants with conditions of introducing a new facility, investing in a new facility, or allocating based on future generation where the receipt of allowances depends on how many megawatt hours a particular generator generates in the future. This can create some powerful incentives that may even be more significant than the core incentive of cap and trade system. It allows policymakers to create incentives for very specific behaviors.

However, some of these allocation decisions can introduce unintentional and costly incentives. For instance, the Lieberman Warner bill has one example. Let me give some background. One of the most cost effective sources of emission reductions in the electricity sector is not changing the operation of existing facilities, and not prematurely retiring existing facilities, but shifting the types of generation investments of utilities and IPPs. A cap and trade creates an incentive to shift investments towards non-emitting or low emitting generation. However, under the current version of the bill (and it may change), new fossil fuel plants will get from half to one ton of allowances per megawatt hour. However, new nuclear or renewable plants will not get this allocation. Clearly this is a perverse incentive. If you build a fossil fuel plant you get a bunch of allowances conditional on how much you generate. If you build a renewable or nuclear plant you don't get any allowances.

Let's consider distribution issues. A cap and trade system could impose concentrated burdens are particular firms, sectors or populations. Impacts will have initial costs but it's difficult to determine where those burdens are ultimately borne. In the electricity sector all costs will initially be borne by electricity generators in the form of allowance costs. Some of those costs will be passed on to consumers in the form of higher rates, dependent in large part on the firm and the particularities of the given market.

For instance, in restructured regions some of the initial costs will be borne by generators in the form of lower profits, and some by consumers. However, in regulated regions almost all the impacts will be borne by consumers in the form of higher rates. The pass through of costs will be addressed by regulators not market dynamics.

One justification for allocations in the electricity sector is to mitigate concentrated burdens, those that are disproportionately placed on particular firms or populations. There have been definitive statements made about the impact on generators and the need for allocations to offset adverse impacts. However, it’s likely that profitability will only be affected in market areas. Further, there’s still a lot of uncertainty about whether some of these costs will get passed through in a market dynamic; much of the analysis doesn’t capture the real competitive dynamics of the markets.

For instance, the extent and the direction in which cap and trade affects natural gas prices will have a significant impact on the impacts of a cap and trade system on generator profitability. The more natural gas prices the less adversely affected, at least to a point, generators will be. It’s not at all clear whether cap and trade system will affect natural gas prices, or even the direction it would do so. The directional effect will depend on how broad the coverage of cap and trade; for instance electricity sector or economy-wide.

The effects on demand are also unknown, as well as how high the CO2 price will go. Finally, the method of the allowance allocation itself will also be very important. For instance, to return to the incentive in the Lieberman Warner bill discussed just a minute ago. It provides competitive advantage to fossil plants on the order of 1-2 or more cents per kilowatt hour. This can really affect the impacts on generator profitability, apart from how many allowances are allocated.

Second, there's a great deal of heterogeneity in how different generators are going to bear cap and trade. It’s not just the difference between coal versus gas, but whether it’s in new England, Texas, or California. Some analysis has stated that only 10% of allowances need to be allocated to offset profitability impacts on a particular sector, however there’s a lot more uncertainty in all this. If the allowances are not addressed in a nuanced fashion we may have adverse impacts in some areas and windfall profits in others.

Let’s consider a seven dollar per ton CO2 allowance price on electricity rates in various regions throughout the country. Clearly most legislation is pointing to much higher CO2 rates. The impact will obviously be dramatically higher. At 7$ CO2, most restructured states will have an average rate increase around 0.5 cent. Regulated states will be around a 0.6 cent average increase, but with much greater variability. The Midwest gaining almost a penny, and the Northwest with almost no increase at all.

One motivation for distributing allowances is to mitigate some of these impacts for consumers, either broadly or at least those in particularly electricity intensive sectors. One needs to be very concerned about how these impacts are mitigated. It's one thing to mitigate the overall electricity expenditures that consumers bear. It's another to adjust the rates because electricity demand response is a key contributor to achieving cost effective emission reductions in the electricity sector.

If a goal of the allocation of the allowances is to mitigate particular impacts on the profitability of firms or on consumer rate impacts, it's going to be very challenging to determine the correct level of allocation. This could be particularly hazardous, and grant some entities windfalls as happened in the EU.

Speaker 2.

Before I begin, Resources for the Future, a non-advocacy think-tank, just put out 15 memos for policymakers concerning climate change on their website. This is primarily economic analysis, vetted with 24 major industries. It's called Assessing US Climate Policy Options. It is useful research.

My remarks will be comparing the SO_2 system of 1990 with today's proposals. The 1990 Clean Air Act included the acid rain provisions and the SO_2 trading system. However there are some real contrasts. Today there is a remarkable consensus on the Hill that carbon trading is the way to go. The Clean Air Act legislation took two or three Congresses before it passed in 1990. Acid rain was kept off the table during the original iterations because there was a 10-year study to figure out whether acidification was happening in the lakes of New England. Alternately, there is an enormous absence of the preparatory work on Capitol Hill and the regulatory agencies, in the trade associations, in the corporate headquarters for the legislation coming into play right now. People really need to get up to speed on the complex background knowledge environmentally and economically.

There is also an absence of experienced leadership in carrying these complex legislations through the US Congress. It's hard to move complex legislation. Further, the President has a major political role. President Bush I, introduced a whole series of proposals on reforming the Clean Air Act in 1990, and one of those included the acid rain provisions. All the major features that he recommended were adopted. They were not in dispute, and nobody was able to change the cap. Nobody was able to change the timetable. The entire electric utility industry was unusually united in trying to change the cap. In the Energy and Commerce Committee are 44 members. The utilities could not find one to kill that amendment.

The big fight back then was how to allocate the credits. The Midwest got victory by getting a few more credits into Ohio, Indiana, and Illinois. It was a cost sharing argument and brought those folks on board. It was also successful because it was part of a larger bill in which so many interests had so many big stakes that it got lost to some extent, except by those in the electricity sector.

Let's compare the two trading systems. First, there is a major scale up from SO_2 to CO_2. The scope is probably going to be economy wide. Second, there were about 3000 SO_2 emitters in 1990. For CO_2 it depends on whether it's upstream or downstream. If downstream one can magnify this by thousands more emitters. It doesn't mean it can't work, it's just significantly more complicated. Third, there's an enormous amount of wealth involved. Further, people realize that it's significant. They weren't necessarily aware of that in 1990. The auction proposal was not on the table in 1990; everyone just assumed they would be allocated. They went mostly to the emitters, with arguments about which sectors. The experience with the European trading system really changed that perspective because it seems some players really made big bucks from the allocations. This really made auctions possible on a political level, and the economists have argued for them from the beginning. There's no question that some element of this is going to be auction.

The battle over potential allocations, and the fact that they can go to different players, even ones who won't be regulated has created a complex political situation. However it also has created an opportunity for people to sign onto carbon trading because they may do well under the proposals. For instance, the Warner proposal has 10% going to the states. This increases their interests, and also gives them the potential ability to change the market if they coordinate actions.

It also can be used for incentives. If someone uses carbon capture and storage then they may get additional allocations. Politicians will certainly be advocating certain plans as a way to get re-elected.

Let's consider the upstream, downstream dispute. This is very different from SO_2. The SO_2 legislation was strictly downstream, the utility as emitter. Now the upstream option is available. We calculate CO_2 by virtue of the fuel input, and we pretty much know the minute we take coal out of the ground, or oil or gas out of the ground, how much CO_2 we are going to put into the air. One option is to shift this to an upstream regulatory system, and give away the credits downstream.

Lieberman Warner has a mix of these things. For instance, do coal upstream, and something else downstream. The political fight today is significantly more over design features than in 1990. Those are still not settled. There are new wrinkles all the time, and the various legislation is very fluid. Senators are trying to be careful. There will be major fights over those features and the credits will be very, very significant. If they really go to full scale auctions, they will be of a size that we've never anywhere, anytime, anyplace.

Another question is how much delegation of these decisions will be made to some executive agency by the Congress. The Clean Air Act had strict formulas of allocation. Alternately, the new California legislation delegated virtually all the serious questions to executive agencies on their climate change. Congress clearly won't do that, but they may to some degree.

I'll finish with an interesting policy proposal. A climate Fed. The Federal Reserve has an amazing position in American politics. there have been proposals for a similar agency for health care, carbon credits, and the strategic petroleum reserve. The idea is to reduce the politics of decision-making in each of these areas. Consider that in the 1990s the Fed was being attacked by the left, and now it's been under siege at times by the right, so it's clearly navigating political waters carefully.

Speaker 3.

I'm going to discuss things from the perspective of a political scientist, not an economist. I'll discuss allocation in 1990 and also in EU ETS [Emissions Trading System]. Emissions allowances are discussed as an unprecedented problem, but in fact it's been done for years, literally centuries. Governments have been in the business of creating licensed rights and public resources for a long time. A private right to emit a pollutant is the same thing as mining rights in the public domain done over 150 years ago. In fisheries individual transferable quotas are similar, as are broadcasting rights overseen by the FTC. We can learn things about allocations from non-tradable and tradable rights.

Second, there's a notion that these rights will or have been in the past be grandfathered. In this context, giving them for free to the current users of the resources, based on the status quo distribution. This is often described as being politically inevitable. However, we almost never distribute the resources based simply on status quo use. For instance, state allocations of SO2 emissions in 1990 differed dramatically from actual use patterns and some states got hammered. Indiana, Ohio, Georgia, Illinois did very badly. Florida, and Montana - clean states, growing states got more than their status quo emissions in 1990. Instead there's various principles that get taken into account.

Society has strong norms, ideas about who should be entitled to resources. Norms of ownership are very powerful in constraining the allocation auctions that we have in many of these political settings. There are four primary ideas: possession, beneficial use, greater good, and egalitarianism. All four have been used in the allocation of emission rights. These four ideas break down across redistribution versus the status quo, and the other line of individual rights versus collective benefits.
but right now I'm not going to talk about that at all. I am going to talk a bit about SO2, hopefully not repeating too much what was just said, and then a little bit more about the allocation, particularly in the United Kingdom in the phase one National Allocation Plan as part of the EU ETS. So moving right along.

In the Clean Air Act amendments of 1990, the allocation was based on historical levels of energy use, and a benchmarked emissions rate. It was not the status quo but free allocations based on the amount of energy they actually consumed and a fixed rate of emission which varied greatly amongst different states. That's why states like Indiana got such a small share. Some allocations based on permitted rates occurred for some clean facilities. Some generators had emissions that were lower in practice than the legal limits. They argued that because they over complied with the law they get a smaller share of the pie. Congress actually listened and allocated on their permitted rates.

Strangely, these allocations are in perpetuity. In 2150, the same facilities will be getting the same allocations that they got in 1990, even if all of those facilities have long since been shuttered. This was a Lockean notion of allocation based on prior use combined with an allocation for the greater good.

In the EU there's a very different set of rules to begin with. First, there was a central authority that dictated what each country could do. No country could auction more than five percent of the allowances. They also required that countries provide new allocations for new entrants. The EU rules were more explicit about providing access to new entrants, and not being able to discriminate in terms of international competitiveness between countries or sectors.

This played out in the UK quite differently. The UK had specific responses within the overall EU framework. They wanted to allocate based on the notion of need. Get economists to determine by macroeconomic modeling what different sectors of their economy would need in the next five years. It's not historical but projects forward. They allocated within the sector simply by pro rating the existing emissions. A big emitter in that sector, cement, energy, whatever, would get a similarly large chunk of whatever that piece of the pie was based on those projections of need. The big losers were electricity producers, particularly because of Kyoto targets. In terms of philosophical approach this was more possessive. There's a tremendous difference from historical use and benchmarking to economic need and historical emissions.

Alternately, there is no allocation for a closed installation in the UK. Presumably one would shutter a highly polluting or high emitting facility, but there's a perverse incentive there that they would then lose their allocation. Instead they keep it open to continue to receive allowances. The UK severely limited credit for early action. Actors that made reductions early on, didn't do as well under the UK program as they did in the US in 1990.

The EU had little time to develop the policy they implemented. Second, they were focused very much on allocation driven by need. Countries were worried about international competitiveness. They wanted to protect their industries by giving them what they needed, so they wouldn't be undercut by production in another part of the EU or Morocco or China, or India. Second, with SO2 the technology to reduce emissions is more well developed. They did not have much of an emphasis on benchmarking like the U.S. This is ironic. The EU has a reputation as being more environmentally sound and friendly, but benchmarking is perceived as being more environmentally friendly model.

The EU had price volatility problems. They had a continuing updated allocation. There were many expiring allowances at the end of the first phase. While the price had been approximately 20 Euros a ton for much of that first phase, people figured out somewhere in the last 12 months that they had wasting assets that were about lose all value, and also that everybody had overinvested in allowances. There was a surplus of allowances that could only be used for another nine months. The price went from 20 Euros a ton to under a Euro a ton in a very short period of time. Phased allocation processes can create this kind of a problem.

Politicians need to move beyond the piñata model of allocation. They are heavily constrained in their ability to allocate, it's not simply smashing the giant plastic donkey and everybody scrambles to get as much candy as possible. There are real limits in terms of what can be done because of normative constraints. In the current situation, egalitarian arguments about the world's collectively owned asset of atmosphere have emerged. This was unheard of in 1990.

The EU experiences show that it's vital to get the cap right. Theirs was simply too high, and created enormous market volatility and uncertainty. Some folks lost serious money.

Periodic reallocation is not necessarily a bad thing, as long as it's done carefully. You really do have to balance the notion of fairness. It's not clear that somebody with a plant in 1990 deserves allowances in 2100. However, if it's done badly it can create perverse incentives or volatility.

From my perspective auctions and benchmarking are better models of allocation. They avoid a lot of perverse incentive problems. They reduce politics; get the government out of the project of predicting or choosing winners. Even 5 years ago many thought auctions were a crazy idea but they are clearly part of the agenda right now in the U.S. The UK will now be auctioning part of their allowances in Phase Two.

Question: I'm not clear on the UK system versus EU system. What's the interplay there?

Speaker 3: That's a good question. All 18 or so EU states were involved in their emissions trading system. There were some central rules created by the EU Commission on the Environment; in part to meet the EU bubble under Kyoto. This is an 8% reduction from their 1990 levels by 2012.

However, then each country set their own allocation plan within their nation. There was a lot of experimenting potential. In Phase 1, they did the same things. It's diversifying now. The UK is simply the model I chose to examine for comparison.

Speaker 4.

I'm going to focus primarily on issues with RGGI's design [Northeast Regional Greenhouse Gas Initiative]. I'll discuss some simple issues. An allowance is a public asset. The public owns the right to degrade its commons and if permission to degrade the commons is given to others, it should be sold at a fair market price. That's the general normative conclusion.

Second, selling the allowances internalizes all of the costs within the program. It wasn't done this way with SO2 allowances. In that context everything was regulated and through the rate-making process society could recoup any possible gains. However, the full price was not necessarily built in from a market clearing perspective.

I'll focus on different aspects the impacts of allowances in competitive and regulated markets. RGGI jurisdiction is all ISO and RTO land. It's a competitive wholesale market. Most of the states have indicated a preference for a 100% auction. The subtext is that the right to pollute in the wholesale market economy is just another cost of production. You need the allowance to emit the CO2 and it's paid through a market system. It's included in market bid costs. There's a new stack that's better because it reflects more of the true social costs of the production process.

A critical point concerning opportunity costs, especially for non-economists, is that generator emitters charge for allowances in their bid prices whether they receive free allowances or pay for them at auction. It's an opportunity cost; the way economics is supposed to work. If they receive it for free, it's still a valuable market asset. It is consumed and exhausted in the process of producing the product. It's part of their marginal cost of production. This was a critical factor for policy decision-makers in RGGI.

Price savings in the RGGI area focus around natural gas. The fuel type dependency has an impact on who wins and loses. In the Northeast, gas generators usually set the price. They will include about a half an allowance dollar value in their bid because they emit about a half a ton per megawatt hour. Coal plants will tend to lose under this scheme. Alternately, there is already a market-clearing price set above their normal costs. So coal generators will be receiving less margin, but still not suffering a lot.

If there are allowances allocated, they will either be given to the states to give to their generators or go directly to generators. If the allowances are allocated to generators in a regulated area, regulators will not let them pass through costs. However, in market areas, allowances will be passed through because there's no regulator to limit the passing on of the opportunity cost.

In a 100% auction, regulators should allow prices to reflect all true costs, including carbon permits. In a regulated area, the emitters will not get the market clearing price bump that non-emitters will get in a competitive wholesale market.

It's bizarre, because competitive markets will include the costs of allowances in the market clearing price, period. Very simply, because natural gas sets a high clearing price in the markets, coal and oil emitters have previously had extensive margin. Now their margin will be reduced.

If regulators in traditional markets do not include permit auction costs, their prices will be lower than competitive regions' prices. Regulated markets already tend to have lower prices than competitive areas. If allowances are allocated for free, then regulated markets will also gain a greater price advantage than competitive markets.

This is important because the price signal is huge. In order for cap and trade to work, consumers have to respond to the price changes inherent in paying for carbon emissions. And producers need to have price incentives to encourage the development of the ultimate solutions: no CO2, or low CO2. This is not immediate impact, 5-10 years, but rather 40-50 years of technology development. CO2 price increases will become very significant.

The relationship between retail electricity price and percent of coal used in a state is extremely strong, except for the Northwest which has all its hydro. Midwest states that rely on 90% coal have rates around 6 cents per MWh. Alternately the northeast, Florida, Texas, and California all average around 15% coal and have rates from 10-15 cents per MWh.

What is the big picture? CO2 will increase costs much more in coal consuming states, but price increases will not be that high. Midwest and Southeastern states will still continue to have prices well below the national average. Northeastern states, Texas, California will still continue to have the highest rates in the nation, the spread will simply be less.

The high price states would argue their prices have always been historically a lot higher than coal price states because of a variety of factors. They've been stricter on environmental and emissions standards on a state basis, they've been planning. Coal states have been emitting CO2 for free for years when it should always have been priced as an externality. So there's an important dynamic between competitive and regulated states.

Finally, I'd like to discuss an somewhat imperfect alternative. . The first choice is to have a 100% national auction of allowances. Further, those allowances should be fully priced into the electricity costs so consumers see the true cost.

If there's not auctions, or if allowances go out for free then competitive states should consider an alternate approach. Utilities should become the regulated entity, not generators. This was considered but ultimately rejected in RGGI but is being considered currently in California. The regulated entity is the load serving entity, the utility, who has to address the cost of carbon permits. It's important in the California context because so much of the CO2 emissions associated with the electricity use in California are from imported sources. This is known as the leakage problem. A cap and trade program set for California generators doesn't affect emissions from out of state imports.

This was proposed in RGGI because if free allowance allocation was going to occur, then it'd be better to have the LSEs get them, because they are a regulated entity. Regulators will keep them from pocketing the proceeds. It's being hotly contested in California, in part because of the traditional role of the LSEs as a portfolio manager looking for least cost ways of mixing in energy efficiency acquisition and renewable energy acquisition.

The approach is imperfect. It raises a number of auction dispatch commitment and CO2 attribution problems. It would clearly need to be carefully developed. To have some natural experimentation with different states and regions will help us understand better how to create a really good federal program.

Question: I'd give up almost anything in the design of any program if it made it more likely that China would join in. For instance, if there is a perpetual allocation of permits to an existing entity in the U.S., it's an enormous asset with a high price. This would create barriers to entry. Alternately, if we extended a cap and trade program internationally, they would lower prices artificially to get the Chinese on board. Suddenly we've created an international farm lobby, right? [laughter] Another example is our ethanol subsidies so we can't take Brazilian ethanol in.

Is future international participation considered in the design of these programs? Does it make a difference for the ability to expand internationally, especially to India and China? What are your thoughts on this?

Speaker 3: China is the proverbial 800-pound gorilla in the room in any greenhouse gas emission discussion. India is the 600-pound gorilla right next door.

Cap and trade is a way for a nation to meet its internationally agreed-upon emissions goals. It's an internal question. The international question should be dealt with externally at the Bali conference. I recognize that's not a totally satisfactory answer. Any plausible solution in the long term is going to have to include all of these other countries.

Alternately, India argues they'll take emissions limits right now. An equal per capita distribution of these rights globally. That is great for them and bad for us. We emit probably 10-20 times what they do on a per capita basis for CO2. This becomes a very difficult issue, as most everyone knows. Nonetheless everyone in Bali realizes we have to get them on board, in some meaningful way, or the whole system won't work. Beyond that, I don't have a more specific answer.

Speaker: The China question is compelling. It's extremely relevant to what we do domestically and internationally. China will be brought in overwhelmingly through diplomatic and political pressures, and arguments about their self-interest. Second, the U.S. needs to lead by taking hard action unilaterally. Trying to make a deal will not get this started. We're going to have to demonstrate we are ready to act. That's the presumption of the bills on Capitol Hill now. The Bingaman and Lieberman-Warner bills have provisions to use trade tools as a way to get China, India, and others on board by 2020. That may not be the best policy tool but at least it's being addressed.

If trade credits are a potential stick, the carrot is in the design of these issues. A key factor is offsets. If there are favorable incentives for offsets, and if they are allowed, they could be a very favorable mechanism for bringing in nations like Brazil, China, and India.

Cap and trade systems are viewed as national systems. However, Kyoto negotiations included an assumption of an international cap and trade system. The hope is to set up national systems, get them going, and then, as a second step, attempt to link them up in a global system.

Speaker: This reinforces the fact that allocation strongly affects the support for the initial system. However, this is a repeat game. There's going to be significant material changes to a cap and trade system for this to be an effective solution to climate change down the road. As another speaker discussed, creating relative price stability is important here. Everything needs to be considered: the incentives we're creating and the sort of constituencies we're creating, and how future changes will play out.

There hasn't been enough thought about how linkages among cap and trade systems will be affected by the initial allocation approach. For instance, if we were to link with China in the future, allowance prices will go down and some stakeholders will be unhappy. If we were to link with the EU ETS, chances are our allowance prices would go up.

It’s not clear how allocation decisions would affect a foreign government's incentive for linking with a cap and trade system in the U.S. It’s clear it would affect domestic incentives for such a linkage. Perhaps if there is a system that transitions to auctions over time there would be increasing support over time for a linkage with something that tends to reduce allowance prices.

Moderator: Does that answer your question?

Question: Well, the first time you read Kyoto, it’s clear it’s bad for India. They're not going to join this, and it's going to get worse. The Kyoto agreement was inimical to getting a good long-term solution. I’m concerned that this issue is not getting addressed, and it seems clear that it is the critical issue of overarching importance. It must be the same for RGGI – how does that play into future scenarios with other non-participating states?

Speaker: RGGI from the start was an effort to get the federal government to do something and to begin to determine what good design features would be. More than anything, it was an effort to trigger a catalyst for a better national program.

Question: For speaker 1, you said that utilities who receive a free allocation under a regulated environment could adjust rates to provide the right incentives or price signals to customers. What do you mean by that? If rates are set high to reflect the opportunity cost of free allocations, what happens to all that cash that gets generated at the utilities. Please clarify.

Speaker 1: There are two different issues. One is the total amount of revenue that needs to be collected by a utility to cover its costs and the other is the rate structure for how it collects that revenue. There’s perfect flexibility if a utility chooses to set the rate structure in the same way they do in terms of lower rates for low-income households or for certain end users. Even if they receive allowances for free, most or all consumers are paying a rate that reflects the carbon price signal.

Speaker: They set the rates higher but the costs are clearly much lower. So what happens to the excess cash? Does it go to the bottom line and the shareholders of the utility, or does it get refunded. If refunded, does that take away the price signal for consumers to respond to carbon costs?

Speaker 1: They're not adding cash if they freely allocate allowances to a regulated utility. It offsets a potential increase in costs. It could be that with free allocations, overall costs don't change. While they have to surrender allowances, they get them for free. They would adjust their rate structure in a way where given the same need as before to collect revenue to cover their costs, the rate structure has now been adjusted in a way that creates higher marginal prices. In order to keep revenues constant, this reduces the rates on infra-marginal consumption.

Question: Am I missing something? If they set the rates to account for those opportunity costs, isn't that going to be a higher rate on average?

Speaker 1: A higher rate, but the rate to care about is the rate on the margin. So just as there are a lot of utilities that will charge different rates for the first, say, 100 kilowatt hours of consumption, and then for the next 100 kilowatt hours of consumption, one could alter that marginal rate without changing the total revenue collection of a utility.

Speaker: The last 10% of someone's consumption would then be charged at a much higher rate?

Speaker 1: It could be. There’s flexibility. Utilities have discretion. There’s no need for an auction to ensure that rates on the margin reflect the price of carbon.

Question: Ok, let's say you did take that and an effective rate was only marginal. Some complicated analysis of historical use could set credits back to every consumer. However, this creates potential for not getting it right. You could over-credit some folks and they would have an incentive to consume a lot more, an under-credit.

Speaker 1: Obviously there's complexity to it. The main point, is that correct pricing in these regulated markets does not hinge on auctioned allowances. Even if there are 100% auction allowances, we can't be guaranteed that regulators will decide to allow the utilities to recover those rates in a way where marginal rates reflect carbon price. There's a lot factors.

Speaker: We generally talk in broad categories of plan owners, in regulated areas and deregulated or utility-type owners. It's much more complicated than that, particularly in the regulated areas. Many of the contracts that have been written for forward sales of electricity transfer the dispatch right away from the plant owner. The person that owns the dispatch rights for the plant does not see the costs. Those costs cannot be passed back by contract.

Speaker: Long-term bilateral contracts came up as a major issue in RGGI. In competitive markets the idea is to put risk on the new generators. Regulatory risk is a significant component of risk always. Since 1992 the possibility of CO2 regulation has been pretty clear. It is a different situation and circumstance. There are different winners and losers, but from the point of view of the competitive market, those risks are appropriately taken by market participants.

Question: In terms of carbon markets, I'm more concerned about Pennsylvania right now than I am about India or China. [laughter] The RGGI folks have not addressed the leakage issue. It's just been left for the future. Plants in New Jersey, Delaware, and New York will be at a real disadvantage because of the participation from Pennsylvania in PJM. It could end up with consumers paying a higher price for energy and no improvement on the carbon front.

Speaker 4: The point of RGGI is to provide a provocation for a federal program. However, leakage is a big deal for RGGI and California. The work there is good so far. They don't know there's going to be a leakage problem yet. Right now the major complaint is that the cap may be over-allocated. They may have a fat cap; more allowances available in the cap than business as usual emissions. Leakage needs enough of a price incentive to overcome the transmission and other costs.

The best solution, and lawyers are arguing whether it's legal, is to put caps on the generators and then require imports to have their own allowances. This adds complications and concerns for gaming, especially in California. So in Pennsylvania they'd sell the clean stuff into New Jersey, New York and keep the dirty stuff at home where you don't have to pay a higher price for it.

Speaker: Some folks have been trying to figure out how to do within PJM what they're trying to do in California. It's difficult, because they don't have bilateral contracting. So for instance, folks who want more efficiency in New Jersey have no solutions for the leakage issue.

Speaker: If you have more efficiency, then there's less load, and less carbon emissions. And that's all off the margin, which is mostly gas. RGGI will cap emissions at business as usual levels in January 2009, and hold them steady for 2 three-year compliance periods. Load growth will be 1-1.5%. That's the efficiency that will have to be found.

Question: What will be done with auction revenues? One suggestion was to reduce distortionary taxes in the system. Alternately, they could be focused on further reductions in CO2 emissions. For instance, increased investments in R&D, and energy efficiency. There are a lot of market barriers to energy efficiency.

Speaker 1: To clarify, revenue recycling to reduce distortionary is not necessarily the best approach. It's just part of the debate. It's politically probable and pragmatic to tie tax policy to climate policy. Nonetheless there is an opportunity cost associated with the allowance value. We need to think carefully about how we use it.

There may not be a clear relationship between the value of auctioned allowances and carbon reduction plans. If auctions raise $100 billion, we may not have clear and efficient uses for that money solely in carbon reduction. It may be more efficient to put some cash in other useful activities. It's important to spend the money efficiently.

Speaker: There's a cautionary note for state regulators. The monies collected by the federal government for Yucca Mountain, never quite ended up going to their intended purpose. The federal government has not been good at correct revenue allocation, so we shouldn't count on that.

Speaker: All the auctioned money in Lieberman-Warner starts at around 27% of the allocations. It all goes into something called the Climate Change Credit Corporation; all set for technology development. There are serious concerns about how the money gets spent and if it gets spent well.

Speaker 3: It may be useful to recycle some of the money for low bracket tax payers. Higher energy prices are very regressive. Facing constituents who are facing even more increases for heating is tough. It's easier if their taxes may be a bit lower.

Speaker: I'm not sure that funds should be funneled 100% to low carbon and no carbon long-term solutions. It would help to lower the price to some degree, without losing price response. However, if research is fruitful it may give us cheaper energy solutions in the long run. That may be ultimately self-correcting.

Speaker: There's no obvious connection between what we need and how much money we may have. There are people who argue that 50 years will create a radical transformation of the energy system with significant technological changes that we cannot foresee on the horizon. If that's the case, the money from auctions will not be nearly enough. We've had massive technological change in some areas, but not so much in electricity generation.

Question: The leakage issue is important in California. About half the carbon footprint in California comes from out-of-state imports but they only constitute about 20% of the energy mix. It's a relatively clean fleet in California. They are considering very convoluted regulations to address this.

At the recent NARUC meeting, there was concern about windfall for carbon emissions. If there is gas in the margin, it's probably a wash. However nuclear power plants will get a windfall, they are not producing any carbon. It was seen as a bad thing.

Second, there were discussions about giving money back, and concerns that carbon policy will not be reflected in rates at all. New technologies will be tremendously expensive. The McKinsey report clearly shows that energy efficiency is the best payback. It's very expensive. It requires substantial money and/or much more significant reduction in consumption. How do we create a structure that balances those conflicting goals?

Speaker: In the competitive market, the CO2 add-on is set by natural gas, and that will be about a half a ton. And below them are the oil and coal producers. They will lose a bit, but they are a low cost provider. They'll get less profit, but they'll still make a profit. There's also complications with hedging and long term contracts. To my mind a 100% auction addresses all the concerns the most efficiently.

Speaker: The whole windfall notion is fascinating to me. It goes to this question of who's entitled to something, right? It seems weird to give a nuclear plant allowances that it doesn't need. Even in an auction that's exactly what they're doing, except by inverse, right? They're rewarding them by making competitors buy allocations that they don't have to buy. It's inconsistent, an auction is fair, but allocations are not.

Ultimately we need to have higher rates, that's where the rubber hits the road. A fairly substantial public education campaign is needed for higher rates. For greenhouse gas abatement or infrastructure development. It needs to be justified and done in ways that are not regressive for lower income folks.

Speaker: This is all about trying to change behavior. That is the goal here, and it's being done with price. However they're also trying to protect the consumer. Well, that protects them from having to make any changes now. Some argue for a transition. This is by and large nonsense. The sooner we get started changing behavior in this country if we take this seriously, the better off.

There is a real question about where the point of regulation is and how that affects incentives. Is it at the load-serving entity or at the first seller? Who has the incentive to change behavior? If it's at the load-serving entity, it puts the higher incentive on the cost being passed through and therefore shaping consumer behavior. However, it reduces the incentives or changes them among generators as to who's going to operate. So outside-the-state coal plants might have an incentive to co-fire and be more effective. This is a key question California is facing right now.

Speaker: There is a key trade-off in climate policy: distributional impacts versus costs. When Kyoto was signed, gas prices were much lower. Fuel switching was going to be the main way to achieve emission reductions. Demand response was not as important back then.

There are 2 current views. One is that there's still a lot of cheap cherry picking to do in efficiency and other areas, as the McKinsey study described. Alternately, another camp believes that consumers are fairly rational on the whole and that demand response is going to be costly. In either case, one can't just look at the cost of demand response in isolation. It should be assessed in relation to the costs of other means of reducing emissions. In that case it is a very cost-effective approach to reducing emissions. Even with a $10 carbon price, demand response can account for as much as 30 to 40% of the emission reductions that are cost-effective.

Moderator: It's good to have customers with the right price signals. If it's done too fast or too much then they can't pay their electric bills or we lose jobs to China or India. If so we'll have new politicians very soon and they won't be passing climate change legislation. The whole purpose of auctions or allocating no-cost allowances to current emitters is to ameliorate the rate of that rate increase.

Question: Will there be credit requirements on products that we perceive to be high carbon emission intensity? This would be done to stop trade imbalances with countries that have no carbon controls.

Speaker: There's some discussion, similar to England. But it's not the electric utilities. It's their end-use customers.

Speaker: All research I've seen has suggested that environment standards have been very unimportant in firm relocation. The price of labor just dwarfs environment standards for all but a few industries. That may be different in a much larger carbon market.

There are innovative thoughts to bring India, China, Brazil, and others in. The EU clean development mechanism does this right now. Europe is complying basically with their Kyoto targets by reducing emission in China. Their cap and their ETS is pretty much status quo, which is why the allowances weren't worth that much at the end of the day. In some sense China, India and Brazil are already participating as participant states for CDM and offsets.

There's been discussion about bringing countries in gradually as they hit a certain level of development and pegging their initial allocations to an efficiency standard, like emissions per unit GDP. That's a promising idea, and the kind of thing we can look for.

Speaker: With leakage, there's different concerns for different industries. Some are more predisposed to leakage than others. This calls for different allocation approaches for different industries. There's no reason why we should be taking a sort of one size fits all approach to every single industry. Of course it makes things a lot more complicated.

Second, there's a big difference between the effect of allocations on the competitiveness of firms and on their firm value. It's not how many allowances you give to a particular firm, but rather how you give them to that firm. For example, during the California electricity crisis aluminum smelters in the Northwest had free allowances for electricity at below market rates. It seem this protected them against competitiveness concerns. However, they shut down their operation so that they could sell that electricity to others who were willing to pay more for it.

Likewise, if one gives allowances to firms that are in competitively sensitive industries one shouldn't do it based on historical factors but based on their future production. Otherwise, if those allowances become valuable, they'll close up shop and sell those allowances off. Setting an allowance based on future production is critical here. Of course one still has to be concerned about creating perverse incentives too.

Question: RGGI does have a leakage problem. Even at a $7 allowance price, the modeling shows sharp increases in RGGI-attributable leakage in the region. It's independent of load growth, because leakage will take place even if energy efficiency is enough to take care of load growth. A simple solution is to determine the amount of leakage that's attributable to the carbon cap and then retire that amount of allowances from the system. RGGI is pretty long on allowances currently. This would solve a lot of problems.

Speaker: What leakage really does is make the price go down at the same time that it makes the net allowances still go down. They end up paying a lower price through leakage, because more cheap juice is coming in. Your approach could work. There are other inefficiencies but it could work.

Speaker: If you have leakage combined with a system that's long on allowances, you may also never have a robust enough market emerge because of those factors in combination.

Speaker: Leakage doesn't occur until there is some avoidable price. They're sequential and RGGI has a fat cap and one hopes that a federal program occurs before leakage has to be addressed.

Question: Not necessarily. Once the federal program's going they may not sunset this. There's now an appetite for states to continue further. Are these things really going to go into one program? And if they don't, how can the auctions work? Will mini fiefdoms affect the efficiency of national system?

Speaker: This is important. Not only in terms of what happens going forward, but also the implications for companies in terms of regulatory stability. It's not being addressed in California or in RGGI. Although RGGI as it is now will be effectively moot, it's less clear in California. A federal program will be stronger than RGGI, but not necessarily California. There could be a federal cap and then layered on top even more stringent targets. If one eliminated that California program, there'd be no net change in national emissions. All you'd be doing is just redistributing where those emission reductions occur across the country. California is essentially subsidizing the rest of the country if that happens. As an East Coaster I'm perfectly happy with them doing that if they'd like to.

Speaker: Barry Rabe at the University of Michigan has a good book about state environmental policies related to climate change. He underscores the fact that states are vulnerable. It's reduced maple syrup yields in New Hampshire or whatever. Obviously, this makes no sense without global action but states are doing it anyway. The reasons could be ethical, wanting to flex political muscles. They may continue this even after federal legislation.

Speaker: RGGI states have never said that they would go away if there was a federal program. There was a fear that RGGI would be a catalyst for a truly wimpy federal program. They'll keep it as a backstop. Nonetheless, I expect that the federal program will be stronger than what RGGI's put in place.

Question: We're conflating two things here. One is to drag externalities of CO2 into the decision of what kind of power plants to build. That is what the cap and the trade will address. The other question is how prices are set to ensure consumers change their behavior in response climate change. That's a more complicated problem, but they're separate.

Consumer response is notoriously inelastic. Demand is constant across different price zones. It's similar with demand side measures. It's up to regulators in these states to induce consumer behavior change. It won't come without a carbon price of at least $50. We should be content to solve the question of equilibrating the IGCCs and solar thermal plants and getting to the right wholesale choices. To assume that consumers will move as easily is naïve. Any thoughts on this?

Speaker: There's another piece, too. The new low CO2, no CO2 solutions and development will be a 50-100 year battle. The incentives have to right for this aspect of it too. The subsidies they may get from the proceeds from selling allowances will be good, but also they need a market. They'll need a correct market price.

Speaker: It will take more than carbon price. For instance some argue that coal is much more protected than people are giving it credit for even under these prices. Until one gets to enormously high prices, you will not get the change that people anticipate and that the coal industry desperately fears. There's a good chance we're going to lock in slightly better technologies for another 50 years and not get the change we need.

Speaker: It also depends upon the speed with which a cap is dropped over time. If cap reductions are aggressive we may get some real results.