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HARVARD ELECTRICITY POLICY GROUP
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RAPPORTEUR'S SUMMARY*

Session One.
Federal Transmission Corridors and The New Federal Role in Siting:
Too Little? Too Much? Just Right? or Largely Irrelevant?

In considering the Energy Policy Act, Congress found itself under competing pressures in regard to the siting of interstate transmission lines. On the one hand, many generators and proponents of broad regional markets wanted to enact broad federal siting powers in order to avoid parochialism and single state vetoes of new transmission lines. On the other side of the debate were a variety of parties who opposed any federal role at all in siting. These included a number of states opposed to any preemption of their authority, environmental groups who feared broader market access for coal fired generators, and local groups who felt that local interests were better protected by state siting authorities than they would be by more distant federal officials.

Congress split the difference by creating a federal role in siting, but not fully preempting the states. The Department of Energy was required to perform periodic studies to determine where new transmission facilities were needed, and, where necessary, to designate corridors where, if the affected states did not approve the siting of a line to meet that need, FERC could exercise siting powers. Opposition has come from states who believe that they are being compelled to site or host lines from which they derive little or no value; from environmental groups who do not believe that a corridor should be designated without full consideration of the pollution effects of generators who might benefit from better access to broader markets; and from local groups who do not believe that federal agencies are sufficiently sensitive to local concerns. Some in Congress have already called for repeal of the recently enacted federal siting powers. Are they right to do so? What has been and is likely to be the result of the new federal role? How and when should the environmental impact of corridor designation be formally considered? Will the new

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

federal role ultimately facilitate the siting of needed new transmission, or will it simply be another spinning of bureaucratic wheels?

Speaker 1.

I'm going to discuss DOE's electricity office and some of their recent actions in this area. Their office is divided into three divisions. There's a large scale R&D program that does work related to transmission, conductors, super conducting technologies, energy storage, smart grid stuff. The permitting, siting and analysis group (PSA) handles institutional kinds of questions and then the energy emergency and security branch handles reliability issues.

The PSA group has responsibility for implementing the electricity provisions from the Energy Policy Act of 2005. They analyze transmission congestion, via a report every three years. The first in August 2006 and another in August 2008. They also designate energy corridors on federal lands under Section 368 of the Act. This is different from designation of the national corridors following transmission congestion analysis. They coordinate federal authorizations required to site transmission facilities. Major transmission facilities usually involve several federal agencies and they function as the "traffic cop." They provide technical assistance to states and issue presidential permits for cross border transmission facilities.

They are fairly involved in electricity demand reduction and have facilitated regional scale collaboratives in three areas of the country. They are in discussions with the Western Governors Association to identify promising renewable potential and the associated transmission requirements for that. In partnership with the EPA they are developing a national action plan for energy efficiency.

Let's get a quick update on the designation of corridors on federal lands in the west. They issued a draft programmatic environmental impact statement in November, the comment period closed February 14. The PSA people are evaluating those comments now and a final EIS is due this summer. There is a mandate from the Congress to designate similar corridors in the east. Those plans are just beginning. They signed an MOU with eight other federal agencies to coordinate federal permits for transmission projects. Regulatory procedures will be published in the Federal Register soon. However, FERC will have the role of coordination of federal authorizations for siting transmission projects in national corridors, if that occurs.

Let's get to some core issues. The August 2006 congestion study identified two areas as critically congested and other areas with significant or potential congestion. A national corridor designation is based on the congestion study after considering alternatives and recommendations from interested parties. This includes opportunities for comments from affected states, and requires a finding that consumers are adversely affected by transmission constraints and congestion. The PSA received 2,500 comments on the national corridors. One in the Mid-Atlantic States and one covering parts of California, Arizona, and Nevada.

Each corridor was determined by a "source to sink" approach. Critical congestion areas are electricity sinks and the sources are geographic areas with significant existing or potential generation resources that have insufficient transmission capacity. The draft corridors use county boundaries. If the boundaries of the corridors are well known and easily identified with precision it's helpful to everyone. The Act is silent on the duration of national corridors. DOE proposed a 12 year period and is holding to that. The two corridors encompass the entire congestion areas, which can be quite large, as well as extended areas far beyond them that provide a venue for transmission.

Simply, a corridor indicates that a significant transmission constraint or congestion problem exists, it adversely affects consumers and it's in the national interest that the problem be alleviated. DOE defines their role as one of problem identification, not solution identification. The designation of a corridor does not endorse any transmission project, it prescribes a transmission solution and leaves those choices open appropriate authorities in those areas.

However, the consequence of using that approach is that it leads to the designation of large areas as corridors because of the need to encompass a wide range of possible solutions. If they narrowed the corridor they would be predetermining solutions. They felt that would be inappropriate. There were several requests for rehearing after the two corridor designations and those are still being reviewed.

If FERC jurisdiction is triggered, FERC would conduct all appropriate NEPA, national historical preservation act, and Endangered Species Act reviews. National corridor designations may lead to environmental reviews that are more stringent or inclusive than one done by a single state. Further, an applicant seeking to site a facility in a national corridor still has to obtain approvals if the facility is sited on federal or state lands. Various kinds of federal lands enjoy special protections that are not affected by the corridor designation. It is similar for state land designations.

Speaker 2.

This misbegotten statute poses a lot of problems and controversy even though it has been very narrowly applied by the DOE. Originally I had thought the statute was irrelevant but clearly this will come to FERC sooner than anyone thought. The statute is a political compromise wherein Congress sought to address procrastination at the state level without preempting the states. It's like leaving the runway lights on for Amelia Earhart. There are other more efficient ways to accomplish what this statute aims at.

Underlying this situation is the clear need for transmission. The transmission sector has been under invested in over the last quarter century. Smaller reliability expansions and facilities have come back somewhat, but major projects are still rare. Growth projections for electricity, aging infrastructure, new priorities like renewable portfolio standards and the advent of clean coal, carbon capture and sequestration all demonstrate that transmission is critical. Since 2000 the nation has built 670 miles of interstate transmission across the state lines. In that same period FERC has certified almost 9,000 miles of interstate gas pipeline. This is a non-sustainable situation.

Network industries like high voltage transmission have no natural constituents. There are many opponents unless a line is built to serve a very specific load. Similarly, we would have trouble building the interstate highway system today if society had to confront the same land use, Fifth Amendment, and climate concerns that come up today. The challenge is to address the large need and yet also the countervailing factors. It's further complicated by the jurisdictional split over who regulates transmission.

Congress's solution in adopting backstop authority was a compromise. However some compromises bring the worst of all worlds, they're not workable. Time will determine whether this works as a simple anti-procrastination statute for the states. Some view the corridor designation process as anti-environmental. Some see this as the beginning of migrating siting authority from states to the federal level. If the problems persist over the next 5 years I expect Congress will come back with a more aggressive statute. However, the state pace of application processing has not been glacially slow; their record is generally good. The real concern is getting initial projects started.

Will the statute lead to collaboration and joint action down the road or exacerbate the controversy? Those are tough questions. However, the corridor designation process does not authorize or site a project. It does not deprive states of the ability to act under state law, does not eliminate existing state environmental protections, or subvert regional planning or public participation. It does take land, and it does expressly prevent consideration of alternatives like DG and demand side management.

Ultimately FERC's authority is pretty limited. They are under the purview of DOE, without them FERC has no authority to site anything. However FERC does have authority to site transmission under part one of the Federal Power Act for jurisdictional projects. For instance the Lake Elsinore pump storage in southern California where FERC is siting 42 miles of 500 KV line. FERC's authority is limited by who the facility will serve, the nature of the entity that's proposing the project, and whether the states have authority to regulate that entity. It's limited by the timing of state action. Frankly, the states can make this statute null. Given all these limitations, and all the things the statute doesn't do, why is it so controversial?

In the US Senate, 13 senators recently requested hearings on the designation process. They have concerns about how this is being implemented. They are clearly aware of the need for transmission. Fundamentally the concern is that there's not been enough consultation, or analysis of the implications of the corridors. We won't really know the results until we start to see the results of its use.

The two corridors discussed earlier cover ten states and parts of 220 Congressional districts. That is politically controversial. Local concerns and politics will play a powerful role in any transmission line but this is just a corridor. DOE did exactly what the statute required them to do. It took them too long but they were parachuting into enemy territory. They stayed in the air way too long and got filled with bullet holes. [Laughter] They could have taken a more expansive view of the statute. It's not as cramped as DOE thinks it is. The statute says they can look at factors like economic development, or national energy policies. With climate change, energy security, energy diversity that opens up an awful lot.

However, DOE went safe and simply said there's congestion in these spots. However, even this has clearly not been easy. To respond to all this, FERC implemented Order 689. The rules are elaborate. The main controversy, already in the fourth circuit court, is whether FERC can take jurisdiction over a project if a state denies the application. There's a split on the Commission about this too. FERC has been clear that they don't want to touch this issue. They have a lot of experience under Section 7 of the Natural Gas Act certifying long line projects. They understand the controversies. Nonetheless, their staff is telling applicants and state regulators that they would prefer that state procedures be used instead of EPAct. They have refused to start the pre-filing consultation process before a state's one year deadline for processing an application has expired.

The 689 process has a long time line. It includes a draft environmental impact statement and adoption of a public participation plan. Only after this material is prepared and the projects office gives the go-ahead does the process start. FERC is not going to be an easy process. They are reluctant to have parties exercise eminent domain. They want to work with local communities, and address state level records seriously. They have truly taken this on as a regulator of last resort.

In Order 890 FERC has addressed regional planning. This is what should be done for transmission development. We need real regional plans. In Order 890 the question of who pays for these things up front is addressed. The corridor designation process doesn't do anything like this that gives parties long term transparency. Order 890 does a lot and that's the approach that ought to be taken for corridor designation.

Question: Could you explain the difference in the statutory authority for Lake Elsinore versus the approval of projects under these corridors?

Speaker 2: Part of the Federal Power Act is where FERC approves the licensing for all hydroelectric projects. Pertinent transmission facilities are considered part of those projects. They have sited 5,000 miles of high voltage transmission in connection with these kind of projects over a very long period of time. This is not a lot of transmission.

Question: You cited the figure of 670 miles of interstate 230 KV and above since 2000. What was the end year for that figure?

Speaker 2: 2006.

Speaker 3.

I will discuss issues with reference to the corridor focused in Pennsylvania. I've divided my talk into local, regional and national issues. Pennsylvania has been a retail choice state since 1997. Their siting laws require that a high voltage transmission line is necessary from both a convenience and safety perspective of patrons, employees and the public. The court rulings through the years, most of which predated wholesale market competition, could include promoting the economy, national defense, system reliability, and may include benefit to systems other than the transmission owners. They have a long experience with the PJM interconnection so their perspective is focused on regional understandings of an interstate grid. Indeed, the most recent Pennsylvania Supreme Court siting decision views benefit to competition as a factor that may be considered in transmission siting applications.

Their siting process has standard need determinations, statute requirements on a property by property basis. Extensive interaction is required with landowners, and there are protections from misrepresentation by utility representatives.

Little Round Top is an area near Gettysburg that was the high point of the southern rebellion during the Civil War. It's an extremely important historical site in which a small division of union troops led by Joshua Chamberlain fought off several divisions of Lee's infantry. They ran out of bullets and Chamberlain ordered them to fix bayonets and charge. They routed the southerners and a couple of minutes later reinforcements arrived. Had they not done that it's likely that the union army would have been flanked and possibly destroyed.

Editorial writers in the Pennsylvania aren't exactly sure what the NIETC [National Interest Electric Transmission Corridors] process is, but they know they don't like it. Public reaction has been adverse. They are unhappy that the federal government is intruding into the siting process.

There's a strong concern that the unique lands in the state will not receive due consideration under this Federal process. Pennsylvania has 23,000 acres of farmland that are protected under federal preservation statutes. There are 120 state parks on 283,000 acres of wild scenic or historic value. They have 20 state forests on two million acres and 300 state game lands on 1.5 million acres. A lot of these were created under the administration of Gifford Pinchot who later went on to become Secretary of the Interior and carried that over into the federal arena. A lot of federal parks were established by him as well. The Pennsylvania constitution states that citizens have a right to clean air, pure water and to the preservation of the natural scenic, historic and esthetic values of the environment.

Currently they have a major siting proceeding for the Trans-Allegheny interstate line project. There are 15 days of public hearings in late March and early April and a decision will be made in late June or July. This project and 2-3 other large pending projects have already gone to FERC to apply for incentive treatment and have received it. FERC has been liberal with granting incentives for the builders of these projects; most of it for the purpose of compensating them for the risk of, or the asserted risk, of building transmission lines.

That's the Pennsylvania situation, what about regionally? LMP congestion prices typically get very high in the western part of the PJM region. On the upstream side of the transmission break prices dive because the power isn't being taken and on the downstream side there is a lot of re-dispatch, and prices soar. These grids change minute to minute. They illustrate the dynamic effect of transmission congestion and the fact that it's not predictable. Transmission congestion can be caused by generation outage or a transmission outage. This is true of every electricity grid. No one can afford to build a grid that is immune from congestion, that never gets congested. It's an engineering decision like anything else.

Obviously, wholesale and retail competition are closely related. Effective competition depends upon a couple of issues in addition to transmission. An effective market design that provides rational signals for investment, and mitigation of market power. Load must be able to effectively respond to price changes too. Finally, one needs transmission and generation adequate to serve the load. We, all of us, have inherited legacy grids. The transmission that exists today was built by vertically integrated utilities for their own purposes and has been adapted to meet the needs of the wholesale market. It's been said of transmission planning that the difference between a reliability upgrade and an economic upgrade is five years. Most major projects go in as reliability upgrades.

In the Midwest the majority of generation is relatively low cost coal generation, much of it owned by AEP, one of the largest merchant generators in the United States. The Midwest folks complain that states like Pennsylvania are taking power from them and raising their prices. FERC's allocation of 500 KV facilities as designated network resources may mean they're paying for transmission facilities that really benefit folks in the East. Folks in New Jersey are concerned about transmission projects to New York that will take their cheaper power in a similar manner. Recently New Jersey filed a protest with FERC over a PSE&G proposal to build a line from the Bergen generating station into midtown Manhattan. They are concerned that one of the company's cleanest and most efficient plants will never again be required to supply electricity to New Jersey. It seems to only benefit the citizens of New York City leaving New Jersey ratepayers behind.

New York's problems are self inflicted. New York State's Article ten generation siting law provided a detailed siting process. The New York legislature has been unable to reauthorize it since 2002. New York has no effective means for siting generation in some of the most difficult territory in the United States to site anything. New York ISO has filed a recent report that asks the state to act more quickly to resolve the issue.

The DOE designated the new Mid Atlantic Corridor by county. Their map doesn't show the generation sources and sinks, or the specific congestion interfaces that are the basis of their determination. The flow directions are primarily west to east. Any project in this area can make an application to FERC if they are refused by Pennsylvania. In fairness, FERC's Order 689 contains a lot of indications that it will consult with the states and look at the state record. However, it does mean that any applicant gets to do a review, and if it doesn't go well for them, they can try again at FERC.

The determination of this corridor did involve some leaps of faith, specifically with the use of counties as the jurisdictions for designation. The corridor occupies three quarters of Pennsylvania, it's enormous. It also occupies a good chunk of New York, West Virginia, Virginia, Maryland, Delaware, New Jersey. It stops at the Massachusetts and Vermont state lines.

Clearly there are both regional and national issues. What are the national policies that are advanced by Section 1221? In the old movie Animal House the fictional Faber College motto was "knowledge is good." The policy advanced in 1221 is "transmission is good." Is it, and if so, why?

Transmission facilities are relatively long lived facilities. They can last 60-100 years. It should be influence by national energy policy but it's not clear what that is. It's mentioned in the 1221 legislation but it's not defined anywhere. We don't have a national energy policy now, and we haven't had one since we first came up with the idea in the 1970s.

The American Wind Energy Association has been strongly advocating a concept of a very large 765 transmission grid that could allow for a nationwide 20% wind supply. They have been working with AEP and the national renewable energy laboratories. DC links would add connectivity. It's probably about 10,000 miles of 765 lines. It would allow wind energy to serve the entire nation, and to overcome the interruptible problems for wind. Presumably AEP is interested because they have a lot of coal generation they'd like to sell but that's just my guess. When the wind and coal people are working together it makes people nervous. These presentations have taken a lot of people by surprise. They certainly represent one form of a national energy policy.

Obviously there are policy issues, technical issues, and cost concerns. It probably represents upwards of $50 billion in investment. It's obviously good for both wind and coal power. What about other sources of generation? Is it good for them? How about demand response? What's the impact of the smart grid? This one example of a comprehensive policy has a lot of unanswered questions.

Overall, the problem with 1221 is that it forces a particular set of policies that have not been fully thought out in terms of their implications. We may regret some of the choices later on. This whole process needs stakeholder support, not just lobbyists on K Street.

Question: What goes on in the DOE process, and then what goes on in a subsequent siting process? For example, if DOE doesn't take into consideration the kinds of resources you were just listing it's simply identifying where the congestion is. Is this a problem if that all gets reviewed in the siting process at the state level or at the FERC?

Speaker 3: The process has a life of its own. Once a siting application is made, the discussion of where it should be sited is locked in. It gives transmission advocates an advantage.

Question: What was the purpose for some of the congestion pricing maps you showed?

Speaker 3: The were illustrative; to demonstrate that they can vary greatly; from upwards of $900 down to 30. Actually LMP can go negative. It sometimes happens at night that you've got a nuclear power plant that's running and they can't get rid of the power so it'll go negative.

Question: Does Pennsylvania have a renewable portfolio standard. If so, can you briefly describe it, and if not, is one under consideration?

Speaker 3: Yes, they have a state renewable energy standard law. It's similar to the renewable energy portfolio standards in other states. There are two classes of renewable standards. There's an administrator to administer the credit program. Generally it's confined to resources that are contained within the RTOs that serve Pennsylvania.

Question: You asserted that New York has inflicted a lot of these problems on itself. For instance, you cited the expiration of the generation siting law. I was surprised that you didn't reference the lack of any joint transmission planning or coordination between PJM and New York. It seems like that is a big missing piece of the puzzle.

Speaker 3: There are interchange ties between New York and PJM. However, they're not strong though and a lot of that is New York's choice.

Speaker 4.

I'll be discussing the legal claims behind environmental lawsuits of the Southwest transmission corridor by the Center for Biological Diversity and other environmental groups. Environmental groups with an interest in curbing global warming are particularly interested in DOE's NIETC designation. Given global warming, continuing business as usual emissions will lead the world to vast ecological destruction with devastating changes to the planet's biodiversity. Innovative approaches to energy production and consumption, and pollution control, are needed now. These efforts implicate the southwest NIETC designation.

I will make a few observations that underlie the legal claims. When DOE identified the critical congestion that justified the southwest NIETC, they implicitly articulated an energy demand. On that basis they created a federal option for relieving that congestion where no such federal option existed before. These are important practical and legal consequences. The congestion and energy demand identification, and a vast area designation means that DOE increased the likelihood that business as usual transmission solutions will ultimately be approved. If DOE considered other alternatives, such as demand side management alternatives, then the business as usual solutions would have been at least in part foreclosed at the federal level. That is the kind of result that is needed to address climate change. This principle is complicated by California's RPS standards but I'll leave that issue alone for a bit.

Second, the NIETC designation fundamentally alters the regulatory scheme for the siting of transmission facilities. These had been the purview of the states. The addition of the federal option, with its highly subjective criteria and temporal triggers, has altered the ability of state utility commissions to retain jurisdiction over proposed projects. PUCS now have to expedite their siting review in a year and/or take extra care that there are never any economically infeasible conditions on an approval, or lose their jurisdiction to FERC. This also means that stakeholders, particularly environmental stakeholders, lose the ability to participate meaningfully.

Third, there are problems in how congestion is identified. Both the southwest and mid Atlantic NEITC are based on current and projected congestion. However Section 1221 states that corridors can only be designated when customers are currently experiencing congestion that is adversely affecting them. Further, the projected congestion is based on historical growth data that does not incorporate demand side resources. Thus, the projected congestion may never come to pass.

There are several legal claims under NEPA [National Environmental Policy Act]. DOE was required to comply with NEPA in connection with the broad corridor designation itself. This is separate from site specific decisions that may come to pass in which FERC will also have to comply with NEPA. There are only three ways to do this. One is through an EIS, an environmental impact statement, second is through preparation of an environmental assessment and a FONSI [finding-of-no-significant-impact] that pass legal muster, or third, by invoking an applicable categorical exclusion. DOE did none of these things. One argument is that NEPA doesn't apply but the wording of the EPA act specifically mentions NEPA and states that its requirements are not affected by designations. There is support in case law for this. The Forest Service lost twice in court for similar decisions not to do NEPA when rolling back protections of forest and grassland areas in Roadless rules and the National Forest Management Act.

Their approach is also not supported by DOE's own NEPA regulations and policies. For instance their proposed designation of the western wide energy corridor involves a programmatic environmental impact statement. The same degree of assessment is not necessary in corridor designation but it does demonstrate an inconsistent approach. If DOE complied with NEPA in the corridor designation then it would have been forced to consider the impacts to habitat for 499 sensitive and rare species including at least 95 federally listed species. They also would have needed to address the cumulative effects of the designation on greenhouse gas emissions, and related effects on species more broadly. They would have been forced to develop measures to mitigate those effects, to vet the information used for determining congestion, and to determine what kinds of generation were likely to come from the new transmission. Public comment would have been integrated, and considerations of reasonable alternatives including energy efficiency, demand response opportunities and distributed generation opportunities. DOE felt this would be an inappropriate approach but that meant they didn't develop and consider all reasonable alternatives as they are mandated to do. The lawsuits contend that if a smaller corridor had been designated, it would have foreclosed the business as usual transmission based approaches that bring more fossil fuel sources online.

The Energy Policy Act also requires consideration of suitable alternatives. There are claims under that portion of the act relating to the proper dictionary definition of the term "corridor." The defined area is so large it includes portions that actually are not experiencing congestion. The failure to engage in the procedural analysis at this level at this stage of the designation contravenes both NEPA and the EPA. I expect that we will see these kinds of suits move forward by a variety of groups.

Question: A full environmental review at all levels for this project and others, not just a specific site project for transmission, is the right way to go. It's not a speed bump but instead leads to better decisions as we've seen with the west wide corridor. Decisions from a higher level generally create better long term evaluations.

Demand side management is only peripherally looked at in these contexts. It should be examined more carefully – it reduces greenhouse gas emissions and also saves money for consumers and the utilities. However, many utilities have their revenues tied to their sales. Serious consideration of these alternative options can threaten their financial health. The incentives for utilities and transmission developers, along with demand response and efficiency all need to be considered in total.

Alternately, renewable energy in California is constrained by a lack of transmission. However, this doesn't preempt a full environmental review. A consideration of which kinds of energy types go through the transmission needs to be part of the process.

Moderator: Environmental reviews include the resource alternatives and need to be reviewed before the line gets built. When Congress decided to create a two or three step process, it's not clear when the siting process occurs, when the environmental review occurs, and when the specifications for specific line placements occur. Does DOE do the de facto siting of the facility? One wouldn't want to replicate all this again when line is sited right?

Speaker 4: There should be a different review in terms of the corridors versus a specific site. The broader corridor review takes into account a whole picture view, a specific site would have very specific environmental considerations. A specific location has a more limited review, at the larger level you make corridors that are going to have the least impact in general.

Speaker 1: There is an important place for demand response, renewables, for distributed generation and congestion. These can be dealt with through a number of ways. The question here is one of regional scale resource assessment. This is an important activity but DOE doesn't have that mandate. They don't have the resources either. They may help facilitate it perhaps. It is being undertaken in a tentative sort of way. They are presently discussing an assessment of renewable potential across the west and associated transmission requirements with the western governors.

Speaker 4: Some organizations are concerned because DOE was required to consider alternatives and they only developed and considered one. Had they identified and considered other alternatives for the physical siting of the corridor, this would have moved them toward other locally based solutions. Several stakeholders feel that they did have the authority to look at more options.

Speaker: Previous versions of federal siting backstop legislation before the Energy Policy Act of 2005 were different. They involved a need determination by FERC. FERC would rule upon the need for the line but leave the siting to the states. The argument behind this model was that it would address situations where there was a transmission flow from state A to state C across state B which provided no benefits to B, and B would refuse to site it. Clearly this approach was not adopted.

A lot of these issues could have been better handled at the state level. States can preempt

FERC, form a compact, get Congress's approval and decide these issues instead of FERC. That hasn't happened yet, it's probably too cumbersome and vague. Getting the federal government involved in siting may have been a mistake.

Speaker: It's also clear that FERC is perfectly capable of doing this work. They've been doing it for years under the Natural Gas Act. This debate and the lack of understanding stems from the peculiar nature of the statute. Broad based regional planning is much more effective than debating over these corridors. This simply becomes an additional siting process. We need more stakeholder input in planning the transmission system, the grid and generation generally, but this is a very blunt instrument for doing that, and perhaps an ineffective one.

Alternately, the last speaker alluded to transmission solutions as being business as usual. Transmission has not been business as usual. Now the industry is staring at comprehensive climate change legislation, and enormous wind resources that cannot get to load. The additional siting process under 1221 is a what-if form of environmental review. What if we build it there? What if we build it there? The federal government has no obligation to review the consequences of an action that are completely remote and speculative. However, if one narrows the corridors then it essentially makes DOE the siting agency. They don't want to do it and they would not be very good at it.

Speaker 4: The lawsuits do not take the position that there's no place for transmission. That would be pretty unrealistic. Transmission is not necessarily business as usual, particularly in the southwest. The renewable portfolio standards in California make it more complicated. Alternately, the Sunrise Power link which is currently proceeding before the CPUC will facilitate some renewable energy and access to liquefied natural gas in Mexico. The consideration of transmission should have more than one alternative, maybe a remote renewable only transmission alternative in addition to a traditional source and sink approach. The environmental groups are not universally opposed to transmission, it's complex.

There is recent applicable case law with the requirement that federal agencies consider the impacts of all reasonably foreseeable effects of their activities. In the southwest there are numerous transmission lines that are reasonably foreseeable. The designation of the corridor alters the regulatory structure making it more likely that they will ultimately be approved at some level. DOES needs to analyze the effects of those reasonably foreseeable projects.

Question: Consider the contrast with the natural gas pipeline issue. One problem is we don't price electricity to reflect its real opportunity cost and scarcity. Thus demand side alternatives and efficiency don't get enough attention. Second, electricity transmission is a socialized cost, highly subsidized. Part of these issues involve a fight about the money. If we had strictly merchant transmission investment with no cost allocation question, would that change the situation? Third is the environmental externalities problem. The effects of transmission on endangered species, on vistas like the Gettysburg battlefield. These things are not accounted for correctly. Finally, there's the standard holdup problem, especially with multiple states. A line going between state A, state B, and state C means that state B wants to extract the maximum amount it can along the way.

I'm not sure which problem we're trying to solve here and I'm also not sure about the relative importance. If the pricing is fixed will some of these problems go away? Especially if the costs were no longer socialized? How much of this is externalities, and how much is pricing issues?

Speaker: The biggest barrier to building transmission, in my view, is the cost allocation issue. Who pays is a very tough nut. Many bright people have tried to determine a one size fits all answer to decide who the beneficiaries are and how costs are allocated and over what time frame.

I'm not sure how you get DSM into the siting process practically speaking except on kind of a project by project basis, or with regional planning.

Interspersed with these issues are concerns for climate change, energy efficiency and DSM. These considerations are going to have to go into planning for transmission; the writing is on the wall. The least expensive solutions will have to be implemented in the future; they will be mandated by state commissions. However, those issues have an air of unreality in the corridor designation process. There are multiple state policies, and multiple utilities – it is much too speculative.

Speaker: I'll focus first on the designation of broad versus narrow corridors. DOE could have looked at a broad range of possible generation sources, with existing generation or areas with strong renewable potential, and drawn narrow corridors between those generation sources and load sink areas. This is a problem because one can't know which of those generation sources will eventually be tied up with congestion. The congestion area is by itself large and heterogeneous. If they do it that way it will end up with a spaghetti chart of overlapping narrow congestion corridors that would not aid any decisions. It doesn't clarify the problem at all, it makes it worse.

Second, regional planning is the single most important missing piece. A focused approach on regional planning would support DSM, smart meters, and other smart grid approaches. States need to take this on and implement it in a committed, comprehensive way – that is one of the things that could really improve many of these concerns.

Speaker 3: Absolutely. PJM has a regional transmission expansion planning process that's fairly extensive. One of the advantages is that it includes transmission planning engineers who aren't affiliated with transmission or generation entities, they're independent. There's some stakeholder participation there, it's a fairly formalized process. It's not a governmental process but if you couple it with some sort of a review, one could keep DOE out of the siting process. It's a base to consider all of these things, a more orderly regionally based process.

Question: Leaving aside the externalities for a moment, there are clearly times when transmission brings benefits. Places like Pennsylvania are between points A and point B. Should a place like Pennsylvania be entitled to an economic side payment for the burden it incurs?

Speaker 3: There were several attempts on a regional basis, both at PJM and the PJM states, to devise a cost allocation process that everyone could agree on. They never got there. PJM's tried to suggest using the allocation factor, i.e. the distribution factor which measures the allocation of load at peak day. However, a large transmission line has a lot of benefits besides what occurs on the peak day. The groups could not agree on how to quantify these benefits. FERC's resolution was to say that all 500 KV lines and above are network facilities, and everyone will pay for them. This made everyone very unhappy. I was happy to not have to go to those meetings any more. [Laughter]

Question: The problem is sometimes points A and B itself. For instance, one side benefits from the congestion. If the line is built their energy cost will increase. Does a state have the right to opt out because they will be an economic loser, at least in the short run? Some states have opposed transmission by putting an environmental case together but the real reason is the concern at losing an economic advantage.

Speaker: Yes, this is an important problem. Open access to the transmission grid in the policy act of '92 made the reality of winners and losers inevitable. As long as the issues are addressed even-handedly and everyone perceives a benefit from wholesale markets they're resolvable. However, not everyone believes they get long term benefits from markets. The markets can work even if the problems are not easy.

If you're in Texas and getting toilet paper from a plant in Illinois at a cheaper level you don't hear the people in Illinois complaining that they're not getting the benefit of the toilet paper plant. They get the jobs. The same cost and benefits debate occurred during the consideration of the national highway legislation years ago. It's similar to the transmission issue. Businesses and cities complained that the interstate highway system would permit cheaper goods and services and destroy the economies in their city. I'm glad that they lost that one.

Speaker 2: It's very hard for network facilities to find constituents. It can be very difficult in a federal system like ours to look at long term projects, and to consider multiple scenarios. The only ways I know of to do it well are through regional planning or by nationalizing the process.

Moderator: These issues demonstrate the need for some strong institutional framework and regulatory oversight.

Question: Speaker 3 said that he is concerned if the coal and wind interests are aligned when it comes to transmission siting. Coal companies are smart to invest in wind energy. It's a very logical and natural hedge for upcoming carbon legislation. So there's nothing evil or suspicious about it.

Speaker 3: I didn't say it was suspicious. I said it makes me nervous. [Laughter]

Moderator: But logic always does that to lawyers. [Laughter]

Speaker 3: My overall point is that we need a comprehensive national energy policy that looks beyond the next election. We're making long term investments without long term thinking.

Speaker: There is Congressional legislation that's pending to establish clean renewable energy zones. Majority Leader Reed in the Senate and Congressman Insley in the House have similar bills. This would require federally financed projects to have 75% of the capacity of the line be for renewable energy only. The big concern is for the intermittency of wind resources. I don't think it will move forward because of this.

Question: I believe the framework we have created in the last year or two is encouraging transmission to be built and that's being overlooked. It is a combination of the federal backstop siting authority, and the socialization of high voltage transmission rates, which provide regional benefits. It's also the incentives that FERC has been providing to certain transmission projects. However this only facilitates the investment. They still have to go through the regional planning process and siting; it's still very difficult. Without the framework, there is no transmission getting built. For example, between PJM and New York there is no regional planning at all, even though it is clearly a regional market. Projects like Neptune and BFT are reactions to that lack of regional planning. The public interest is not being served. A lot of the states are unhappy because of the lack of a regional process that they can participate in.

There has been a concern in northern New Jersey about a transmission line that will go over to New York. However, that project has committed to backfill the megawatts going out of PJM. It will be a net gain of generation in northern New Jersey as far as generation. Because of environmental rules they can't put all that generation at the same location so there will be some transmission upgrades which will be paid for by the project. That seems to be in the public interest.

Speaker 3: The head of the New Jersey BPU said it's not in the public interest because that line is a response to the lack of generation being built in New York. They are not building their own transmission grid or their own generation, and the transmission line just enables them.

Question: OK, this brings it back to the environmental issue. In many states, it's very difficult to site generation because of physical restraints and environmental permitting. This means that many regions have to rely upon generation coming from other places. If there were a regional planning process it could be transparent, with proper cost allocation, and good siting. In the DOE corridor siting or in the regional planning processes, should authorities speculate as to what demand might be, or focused on measurable and verifiable demand response? If it's the latter isn't that already included in the load forecasts? Relying upon speculative demand response when building transmission for reliability needs in the future is risky. It takes a long time to build these projects. How should demand anticipation be done to ensure reliability?

Speaker 4: Regional planning has failed to facilitate necessary transmission. That's the prevailing wisdom. DOE's siting authority under Section 1221 to some degree supplants the failure of the regional planning processes. However, environmental reviews at the site specific stage are important because they have to incorporate demand response and renewable in the course of developing alternatives at that level. It is more difficult to anticipate exactly what the demand will be at the designation level. Nonetheless, in identifying areas of critical congestion an energy demand that is quantifiable is being identified.

Comment: When "demand response" is being discussed it may be getting confused with "demand side management." Demand response is very particular to peak loads. In New York it's especially important. Two summers ago they hit 16,000 megawatts as their peak and addressed that via demand response.

In terms of demand side management in general, I don't know how much of that is in the load forecast. Even if there is a significant amount of energy efficiency that could be captured thereby reducing the congestion, one can't minimize the need for transmission. However, you can get a big chunk off before you look at the transmission side.

Demand side management and energy efficiency have huge potential, and it's very reliable. Especially if it's aligned with the utility's financial health. Con Edison is not decoupled so they have little incentive to get energy efficiency without threatening their financial health. The regulatory incentives need to be aligned properly.

Question: Regional planning without regional solutions really doesn't help the problem. San Diego has weekend peaks when the region uses all the energy in that area. Regional solutions need to be much broader, and address all the various idiosyncrasies.

The biggest issue for demand management is an infrastructure problem. Just getting the infrastructure in place takes time and money. But there are three pieces you need. You need the smart meters, you need the smart market prices and then you need smart tariffs to bring the whole thing home. Customer enabled demand response is critical. Southern California is experiencing high loads. Load forecasts are way behind the consumption that they're already seeing.

The motto at the recent DOE forum seemed to be that if one is for renewables, one is for transmission. Is that correct? How do we effectuate a regional solution in the west? Finally, how do we implement real demand response in which customer really get to understand that the price is high at peak periods? How do these pieces come together?

Speaker 1: The Western Governors' work is still in a somewhat nascent state but it may offer some promise. California has looked hard at where renewables potential is and tried to figure out what the associated transmission requirements are. This is a stepwise kind of process. We can't address all the problems in one swoop, they will happen in stages.

DOE's involvement in these regional studies means they draw a line and try to only facilitate these activities, supply technical support from their national laboratories. They work hard to not to shape the actual analysis and leave decisions to the states.

Question: In the context of regional planning and long term focus, let's consider Ohio's situation. Ohio is a little uncomfortable making a sizable investment in transmission that will allow flow to eastern PJM and lower prices there. Have we allowed regions to get too big and therefore exacerbated cost allocation problems? In the smaller PJM, everybody worked together and when some states built something it was understood that the next time it would be built it would be in the other state. It worked. Now regions are larger and there are 13 states in PJM. How do we define a region? Is an RTO just happenstance or should there be something more carefully constructed?

Speaker: A region is the market. With a highly integrated resource at the bulk power level, political distinctions that define a market can't be used. PJM has an organic history with its own interconnection reserve sharing arrangement. The FERC struggled with this problem in Order 2000 and standard market design. How big is a region? It is inevitably arbitrary. The real solution here is how one decides to allocate costs of multiple units over a number of different jurisdictions. There are ways to do that.

Regional planning drives those regional solutions. FERC needs to ensure that the full potential of regional planning leads to real, equitable solutions.

Question: Are market signals accomplishing the goal which is to send price signals to developers of the transmission? If that isn't working then all the other issues don't matter.

Speaker: Transmission pricing is not really part of the market. It's still a regulated service that is priced according to how FERC determines the equities rather than the market. Further, traditional state values are threatened by federal intrusion into the siting process. 1221 says the state gets one year to run its process and if they say anything but yes the parties get to do it all over again in Washington. Then if FERC says yes, condemnation proceedings go in federal district court. This is really something more than a market issue. It involves constitutional and environmental values. It's in three pieces.

Question: We clearly have a significant environmental and energy scarcity problem. Second, the federal transmission corridors are not the solution, or at least there's a lot of disagreement there. Third, the solution for this problem is really complex. Given these situations, could the speakers give a forecast? Going forward, given the economic and political powers, how much transmission will we see built?

Clearly the same amount is not necessarily a death sentence; the congestion rates haven't just spiraled out of control so it's not a lights out scenario. It's not optimal either. What is the transmission building scenario?

Speaker: There will be a lot of variety across the country. Regions of the country with wind capacity have a groundswell of support for transmission. In other parts of the country it's going to be tougher.

Speaker 2: I'm not willing to predict that but somehow this country always manages to do the right thing at the last moment for the wrong reason. [Laughter]

Speaker: In the last five years an awful lot of building was small reliability projects. We will continue to see replacement of aging infrastructure at that pace. The big question in five years, if not sooner, is how we address major expansions of the system to accommodate renewable energy and remote resources. Whether that's a 765 KV overlay like AEP and NREL are talking about, I don't know.

If energy and environmental policy continues in the current direction there's going to be an enormous demand for major investment in the transmission system and we're not going to get it in the next three to five years. Congress will have to address that issue.

Speaker 4: It will vary but overall it'll increase, particularly because of the NIETC designation process as well as the west wide energy corridor and the corresponding policy shift and need for remote renewable energy.

Question: What is the practicality of comparing transmission to alternatives? I want to discuss this in the context of previous discussions concerning California. California is second in the nation in efficient use of energy. The state already has aggressive additional energy efficiency and demand response targets, probably to the point of not even being achievable. These are built into transmission planning forecasts.

Utilities there cannot meet their RPS obligations because of lack of transmission. They have contracts but not the transmission to get the power. There's a real concern that we're just slowing down the process. My point is that there is significant efficiency, demand response, a $3 billion subsidy program already developed for pursuit of rooftop solar, photovoltaic distributed generation. The alternatives need to be compared against transmission. Finally many of the efficiency and DG forecasts are built into load forecasts there.

Speaker 4: Well, the DOE had to include a consideration of all reasonable alternatives. This would have been an open transparent public opportunity to comment and would have gotten a lot of intelligent folks into the debate. There's no way of objectively evaluating whether all of what you're saying. Assuming it's true that would be factored into the analysis of the most prudent alternative.

Session Two.
Monopsony Manipulation: No Cost is Too High to Get Low Prices

The problem of market manipulation by monopoly generators has been a concern of electricity market design from the beginning of organized markets. Economic and physical withholding can raise the price of electricity, and an owner of many generating plants could benefit from the higher prices. Bid mitigation has been the preferred approach to eliminating or reducing the potential for market manipulation. Less well understood is the potential for monopsony consumers to exercise a symmetric practice. Building and operating incremental and otherwise uneconomic generation can lower the price in the electricity market. If the total payments of the load are considered, it is possible that expensive excess generation could pay for itself in reduced payments by load. This is the exercise of monopsony market power. How much does this effect drive the interest in expanded investments in regulated generation? How would this interact with capacity and energy markets in the regional transmission organizations?

Speaker 1.

I will lay out an economic framework for building some surplus capacity in order to lower market prices. What is the problem we're trying to solve? The premise implies that market prices are too high but there's no benchmark to make that judgment. There's a lot of perspectives. There's a difference between "did things turn out as expected when competition began" versus "what should prices be and how should they work going forward?" If market prices are too high and change is needed, then what is the goal that we're really trying to accomplish? What is the feasibility and the cost of trying to lower customer bills?

Let's consider market versus regulated pricing. Market prices are forward looking, they reflect marginal cost, not sunk cost. Regulated prices are based on average costs, historic costs, and sunk costs. They don't reflect marginal cost except to the extent that they get added in and impact the overall average.

A regulated pricing formula is simply fixed cost, fuel, and operations & maintenance [O&M] added together and divided by the sales forecast. The fixed costs include depreciation of original investment and maintenance capital, fixed price contracts, and financing costs. The older the investment gets the cheaper it gets because it's being depreciated. States with old coal and hydro capacity can get power at 1 and 2 cents that was originally very expensive.

Remember that construct and consider two sets of economic conditions in the industry. In the mid 1990s when states decided to deregulate markets there were three important factors. Excess generating capacity, cheap gas, and new capacity that would be cheaper than the sunk costs of existing plants. Excess generating capacity drives the price up in a regulated market. This provided the rallying cry for deregulation. In a market environment excess generation drives prices down. This was the biggest incentive to restructure.

Second, cheap natural gas, $2 gas, brings big savings in the market environment. It also brings the regulated price down as well depending on the fuel mix but to a lesser degree. Third, cheap new capacity brings prices down in a market environment and does so to a lesser degree in a regulated environment.

When deregulation began the average embedded cost of generation in upstate New York was six cents and the nation-wide average was 2-2.5 cents.

In today's environment the same three factors are driving things except everything is turned upside down. Now there is a shortage of capacity. Here is what drives economists nuts. In a shortage of capacity, one needs to build, one needs the cash but what happens? In a regulated system, the rate goes down when it should go up. Why? The fixed costs aren't changing so the price is going down when economically and logically it ought to be going up.

Second, increasing gas costs have the same effect. In a market environment gas is on the margin, and has a huge impact on the price. It's the marginal capacity in a capacity market that needs to increase production and it sets the price for new capacity. Gas on the margin can set the market price at 10 to 15 cents a kilowatt hour.

Finally, new capacity is more expensive than old capacity. The folks with the old coal, hydro, and nuclear plants are still getting it at 2 cents. Folks without those old capacity have a much more difficult time.

Those two situations dramatically reverse in ten years. Generating capacity went from excess to shortage, gas went from cheap to expensive, and new capacity became more expensive than old capacity instead of cheaper.

The market solution is to increase generating capacity to lower the market price. With everything else equal, prices will go down. The more difficult question is would the savings from those lower market prices offset the costs from paying for that excess capacity? That depends on how much, what type and where the capacity goes in. Is the ultimate goal to reduce the frequency of scarcity pricing? Or to change the fuel on the margin to ensure that coal doesn't get a gas price? Who will pay for the excess generation? Does this mean withdrawing retail choice for large regions? Further, if you lower the market price, anybody who buys from the market is going to benefit. There are states that buy from PJM that never deregulated their markets but they will also benefit.

Consider plant generation production for calendar year 2006. In states with deregulated markets, 59% of the capacity and 37% of the energy was gas-fired in 2006. Nuclear has a 92% capacity factor, base load coal at 75%. The problem is it would be extremely expensive to try to add enough different capacity to get gas off the margin a significant proportion of hours. Further, doing this may not be feasible especially if we consider the earlier panel. Can the industry really build coal and nuclear in states like California, New York, and others with open markets?

There's longer term effects as well. If bill savings to consumers were to roughly equal the revenue lost to suppliers then it's a transfer payment. However, suppliers would view this kind of intervention to lower prices and the risk profile would change. Long term capacity would get reduced, and become more expensive.

What are we really trying to achieve here? Marginal cost and average cost are never the same except by accident because they're driven by different things and they move in opposite directions. When one's going up the other's coming down and vice versa. Markets have cyclical patterns. The big question is what happens when that cycle changes again. The industry needs to consider what kind of system works best. Who should decide, who builds, who pays and who bears the risk?

Question: How is it that market prices don't reflect some costs?

Speaker 1: They're set based on what the incremental cost is at the margin. That's how the wholesale markets are structured. That's how bidders work.

Question: It's based on the marginal cost to produce that unit of energy?

Speaker 1: Right. In the ISO markets whatever the last bid is, which is the highest cost bid that's accepted, sets the price for everybody else. The market does not recover sunk costs, the auction is set based on the last increment of supply that's accepted into the market. It will probably cover sunk costs but it's not set determined based on sunk costs.

Question: It's counter intuitive that someone would bid a price that doesn't recover their fixed and marginal cost.

Moderator: Think of farming. [Laughter]

Speaker 1: Consider the 90s. The market prices in upstate New York were two cents. Some utilities sunk costs were six. If they bid six cents they wouldn't dispatch. A build for replacement power quoted at that time by independents for a new gas combined cycle in upstate New York, taxes, regulation and all was 4.4 cents.

Speaker 2.

IPPs have a lot more impact on what the price is coming out of the market than maybe some slight exercise of monopsony or monopoly power. We should be thinking about other things beyond attempting to make markets work perfectly. There are so many other externalities that affect these things. For example, load growth. Are we looking at a world where we're going to follow the gas industry and through DSM we're going to see decreasing growth, or in fact because of plasma TVs, computers, etc are we going to see load growth? That will have a greater impact than building one more generator. Fuel costs will have enormous impact. Environmental retrofits will too. So will efficiency implementations.

Clearly, monopsony or monopoly power activities can have impacts but in the large context it's small impacts. Markets are under significant attack at the federal and state level. Discussions on this topic give people the impression that markets are significantly flawed and that is not the case. Recent anti-market filings at FERC give the impression that the markets are easily gameable.

When you look at the state level we clearly are under this kind of situation. Virginia and Ohio are both worried because their market prices seem to high. They are reacting to this situation.

When I think of the FERC RTO stakeholder process, there has been a lot of discussion around building or withholding capacity. I'm not sure that stakeholder processes are the best way to design markets. I say that as a stakeholder.

These stakeholder processes involve highly paid economists and lawyers to exercise whatever influence they can for their clients. They are a long process where no one gets what they wanted and therefore it should be kind of a fair deal. This works fine when it involves carving up monetary settlements, but much less so when it involves discussion of market operations.

The language around monopsony from the PJM tariff is four pages long. Most people wouldn't understand how it works and how the protection is there, it creates doubt. Let's assume that a 1,000 megawatt load industrial wanted to exercise monopsony power. If they build a generator they purchase less and reduce the price for the purchase for others. Would customers do this? Small load clearly can't do it, it would have to be industrials or a MUNI or a co-op.

Let's assume a 10,000 megawatt market and 25,000 peak capacity. In three different price scenarios – high, medium, and low, the payback period runs from 2.5 – 7 years.

However, in that interim a lot will happen with load growth, generators retiring, etc. No industrial will do this. They avoid doing demand side response energy efficiency because the payback isn't in nine months. Putting something at risk for longer periods is too risky for them. The bigger risk is if government wants to build advance energy, or renewables. Those kinds of impacts are significant, as opposed to one monopsony player taking that action.

In the RTOs there's little flexibility. Everything goes through the energy or capacity market. Some suppliers in regulated states want to sell supply energy on a contract basis but everything is biased to markets, except for contracts for differences, financial contracts. The everything is forced through these administrative markets the more people may try to game the system.

Let's discuss the Ohio experience. This is a state that really wants to exercise monopsony power. They want to determine the price for all generators in the state. They don't want the market or cost of service to do it. They're not sure where they want to go in between. All of this is in the name of economic development.

Buyers in that state can't get alternate contracts because the prices are higher in the future market than current levels. When the market price is lower the PUCO is able to force the utilities to market. If the Ohio bill passes it will always incent lower cost or market. The PUCO believes price is a determinant of whether the market is working well, not does the market work well and what's the price that comes out of it. If one supports markets, we shouldn't mess with them unless there are really serious problems, and steer away from stakeholder process and majority rules for policy setting.

Speaker 3.

We don't normally think of monopsony power. I found that the spell checker won't take it. [Laughter] We may not be talking about the classic type of monopsony power but rather a subtler effort on the part of some states to take pretty extraordinary actions to move prices closer to what they think the right price should be. This would be done through some type of ownership or control of generation that is not economic or through the marketplace. What are the risks and implications of going down this path? First, it's helpful to define market power. Two key points for a definition are that the ability to sustainably and profitably alter prices from competitive levels. Second, it involves rational behavior that leads to inefficient outcomes. However, setting a market price by a high bid is not market power by itself, and similarly an attempt to reduce prices to competitive levels is not necessarily market, or monopsony, power. This conversation assumes a reasonably workable competitive market. Some might disagree that we have those, but I assume multiple buyers and sellers, with generally good information and ease of entry. Obviously this doesn't apply to the southeast and what happens with one utility buyer.

Demand response is often characterized as an antidote to market power, and theoretically it can be. However demand is typically inflexible. However, if prices begin to get quite high then demand can soften and the price will come down. A lot of this depends on whether or not that bid is a market based bid, or if it's being subsidized in generation or on the demand response side.

We can conceive of monopoly power as an attempt to drive up prices and monopsony as an attempt to drive down prices, but both in inappropriate ways. There's been extensive concern and regulatory discussions concerning monopoly, but very little on the other side of this coin. It has come up in a couple of places.

So why this conversation now? The reality confronting the industry involves several issues that have created a lot of anxiety. These include rising commodity prices, and rising costs of new construction. There has also been a long term rate freeze in Maryland, rates were rolled back and frozen for 13 years, Pennsylvania's rates have been frozen for longer than that, and Illinois saw a long rate freeze. There are shrinking reserve margins, and heightened concern for environmental issues. This has created a pressure cooker of political issues that may lead to politically expedient issues which are not necessarily good. State PUCs have attempted to address this issue in a variety of ways. One approach is to over-build generation, which I'll discuss presently.

A key question is what extent the interest in reducing load is driven by an interest in exercising monopsony power. That is not the driving cause. Rather, it is a response to political pressures, an effort to get reserve margins back up, and to regain some control that many state commissions believe they've lost in the transition to markets. Further, some utilities would be very happy to go back into the building business. Nonetheless, just because monopsony is not the primary reason does not mean it's completely off the table.

This question has come up specifically in several FERC proceedings in the context of load participation in the capacity markets. Here are some key excerpts from recent filings. In the Devon Power case where the FERC approved the New England forward capacity market the settlement included certain provisions about the way that load could participate in these auctions. The FERC said that when load owns new resources they may have an interest in depressing the auction price since doing so could reduce the price they must pay for existing capacity procured in the auction. The alternative price rule, the mechanism in the FCM [forward capacity market] settlement, does not eliminate the value of self supplying or contracting to create a hedge against the uncertainty of auction clearing prices. Rather the rule helps insure that load does not use self supply to artificially suppress the auction's clearing price below the price needed to elicit new entry.

Similarly in the PJM RPM order, the minimum price offer rule establishes relevant conditions for determining when sellers can depress prices below competitive levels. These reasonably define when a load serving entity [LSE] can cause market clearing prices to be unreasonably low. FERC's rationale is not whether the LSEs are acting rationally to try to reduce market prices. Rather, it is to ensure that the capacity market works efficiently and produces just and reasonable prices that will reliably guide private investment in electric infrastructure. They are not seeking to enforce the antitrust law's definitions of monopsony power but rather to assure that prices remain just and reasonable. The New York ICAP filing also address this issue.

What about the state side? This comes up generically in the context of whether re-regulation makes sense. There's a number of things that states consider; they include rate stabilization and freezes, state power authorities, windfall profit taxes, elimination of customer choice, as well as generation building. In many cases states have concluded that the markets are not working as they were intended and the status quo provides an opportunity for existing generators to preserve the high prices rather than to build more. The markets have not incented enough construction to maintain reasonable service at reasonable prices. Long term contracting becomes a potential solution. Ultimately it's not the right solution but the state perspective is understandable certainly.

Unfortunately this transfers the risks of newly built generation, whether economic or not, back to captive customers or a state agency with taxing authority. Because these risks are real and they do exist and they have to be accounted for somewhere in this process.

I will focus on two state examples that I've made anonymous as State A and B. Here is a quote from a PSC report issued in state A. They were looking at options for re-regulation and considered their basic situation against a series of alternatives to see what the price impact in the rate would be of adding different types of generation, demand response, renewables, and so forth. It included a test scenario titled "The Overbuild Case." "The Overbuild Case (1200 MWs of combined cycle) produces a significant decrease in wholesale energy prices and a sustained reduction in energy and capacity prices for ratepayers."

Now imagine a filing by a generator which includes a withholding scenario in which 1,200 megawatts of combined cycle produces a significant increase in wholesale energy prices and a sustained increase in energy and capacity prices for ratepayers. That generator would be in FERC jail faster than one could blink. The issue of an overbuild raises different policy issues perhaps but it questions whether there should be more symmetry and similarity in how we approach monopoly and monopsony power.

The State B example is more complicated. That state concluded that an overbuild, they called it an overhang, would bring a series of quantitative and qualitative benefits for ratepayers. This is capacity that participates in the auction in excess of the minimum requirements of that auction. They talk about implementing competitive forces to mitigate the risk of market power, reduce clearing prices, and reduce costs.

However, state B did recognize some of the risks and difficulties inherent in going down this path. They note that procurement of these resources would depress clearing prices in the near term. However a long term benefit would not occur because incremental increase in procured capacity would be beneficial only as long as incremental costs were offset by the benefits based on the clearing price. However they can't know the clearing price until after the market clears. It becomes extremely important to get it absolutely right in terms of how much overhang, or overbuild, gets developed. The 1,200 megawatts may be arbitrary, and not necessarily beneficial.

This demonstrates one of the core reasons this is a risky, difficult scenario. Many very smart people in this industry, including several who ultimately went into bankruptcy, made investment decisions based on good information and analysis about the right thing to do and they were wrong. That happens in markets. States are not somehow smarter or more competent than others in the industry. Who bears that risk? If the states get it wrong then the customers do, rather than companies or their investors.

Second, lower prices are not necessarily good prices in today's environment. Environmental concerns are mitigated by high prices. Right now the environmental issues are largely an externality to current high prices, they're not even priced in. Demand response and efficiency really require prices high enough to incent that behavior.

Further, the risk that the wrong investment is going to be made is actually higher because those decisions are being made politically, not by price signals. States could very easily build both the wrong type of generation and the wrong amounts of generation. The best strategy for only lowering prices is to build peaking plants, knock some of the more expensive gas off the margin. This doesn't get done with a base load plant.

However, this discourages base load investment, which is needed for long-term growth and long-term industry stability. If states go down this path they will scare away all investment. It undervalues the risks associated with the new generation. In order to get the lowest possible price developers will cut corners on facilities which is bad in terms of outages, short term reliability, and safety.

There are significant risks associated with building new generation in today's marketplace. According CERA, new builds are 130% higher than 2000, 27% higher in the last 12 months and 19% higher in the last six months. There's world-wide demand for infrastructure expansions, historically high costs for raw materials, and increasing tightness in equipment and engineering markets. Fuel prices are going to continue to rise. Finally, carbon costs are a fact of the future, and need to considered in current risk analysis. Additional environmental requirements also add to costs.

Further, there are huge political risks. These rising prices create politically risky environments. Maryland, and other states, are actively reconsidering issues that were settled 12 years ago. If one tries to guess the price now over the next 20 years they will be wrong at least in some moment in time.

Further, in market areas, many utilities have lost many of their large industrial customers and almost half of their commercial customers. This means that these risks will be primarily assigned in rate base to residential customers in most market states that decide to go this path.

All this means that we need to let markets work. Let those in the best position to take and analyze these risks, and respond to price signals that the capacity markets are incenting for demand response and new generation. Politicians need to relax, and give this time to continue to work. This is not a crisis. Capacity margins are tightening but lights are not going out and markets are beginning to respond. There are significant increases in demand response and new generation in New England and PJM. It is a mistake to put long term high risk investments on the backs of captive ratepayers and taxpayers.

Speaker 4.

The last speaker made the comment that state regulators are not omnipotent. They are omnipotent. [Laughter] I can assure you. Omniscient, no, omnipotent, yes. [Laughter]

Let me raise some threshold issues that are worthy of discussion. There is still a question whether electricity is commodity; this still needs attention. Just as we have a debate about whether health care is a right or not, there's a question as whether electricity is a commodity. Those who support competition have an obligation to communicate why electricity is a commodity instead of public good or right. If it's then this discussion is rendered moot; market and antitrust implications disappear.

I believe antitrust law does inform our discussion. It's not dispositive. I'm a lawyer by training and the law of antitrust is informative for this session. In FERC precedent there are elements of antitrust in the orders the previous speaker cited. Antitrust also addresses predatory pricing and the long term implications of pricing below market that may have negative impacts on the long term functioning of healthy transparent markets. This is relevant. While I support competition, and it's been supported and mandated in federal law in 1992, and reaffirmed in 2005 amid bipartisan deliberations, the case for it needs to be more cogently articulated by supporters.

Another important threshold consideration is the concept of federalism. I respect the Madisonian concept of laboratories of democracy. The legitimate role of the states in resource procurement should be respected by those at the federal level and by the markets. However, this needs to be balanced by a legitimate federal interest in transparent and competitive wholesale markets. There is a potential negative tension that can arise from the intersection of jurisdiction between states and the federal level. Recent conversations concerning best practices for state competitive procurement between FERC and NARUC have been a real start to a constructive dialogue in this area.

Competitive procurement can be helpful even in a regulated environment. When Arizona embarked on an RFP process for the load for Arizona Public Service Company in 2002 they saved Arizona ratepayers hundreds of millions of dollars. And again, this was a non restructured jurisdiction. Even here wholesale competition had a viable impact. The Arizona commission had sited numerous power plants from the merchant sector and this led to tangible benefits for the consumer.

One has to be mindful and respectful of the political process. The political tumult arising from rising fuel prices is significant. There have been significant requests for rate increases in the regulated jurisdictions at every level, and of every kind. General rate increases, emergency rate increases, super emergency rate increases and PGA increases. The upward pressure in commodity prices is being felt in regulated and market environments.

Let's consider markets and antitrust. Both federal and state regulators have a mandate for just and reasonable rates. Some states still regulate small private water utilities. In that context rates can be unjust and unreasonably high or low. Both of those potentials obtain but the mandate is just and reasonable rates. The monopsony phenomenon does need to be considered.

It is reflected in FERC orders. The old Standard Oil of Ohio Supreme Court decision confirms that predatory pricing creates disincentives to enter the market that ultimately bear on the consumers. This market disincentive can cause unjust and unreasonable high rates in the long run. The unjust and unreasonable low rates lead ineluctably to unjust and unreasonable high rates if there are disincentives to enter the marketplace. To a certain degree those precedents dictate the answer to the question and dictate certain responses by the states. Competition is endorsed to some degree by U.S. law and that is really a key threshold. Rising prices do not mean that competition has failed.

Environmental issues clearly have to be addressed. The extensive state adoptions of renewable portfolio standards underscores this point. They're important issues to our body politic. States may consider them and resolve them in different ways however, so it's better that RPS' develop independent of a federal standard.

Competitive markets are the appropriate mechanism to consider these environmental issues. FERC's recent Tehachapi order used this wonderful term, "locationally constrained resource." It's a term of art for renewables that are not located near load and addresses interconnection costs. Tehachapi portends further federal and state cooperation. A fundamental issue was that interconnection allocation ought to properly account for preferences articulated by the state of California and its elected appointed officials. In essence, certain costs ought to be socialized because the deployment value of wind turbines differs from that of the traditional combined cycle gas turbine.

State initiatives on decoupling are another way to address these issues. They underscore the importance of aligning utility interests and shareholder interests with consumer and environmental interests.

Supporters of competition really need to respond more persuasively to the legitimate concerns of ratepayers. They need to demonstrate how it gives positive results for end use consumers and the environment. Those long-term results need to be articulated.

Question: Monopsony is a difficult problem. However, much of the discussion was not about monopsony, but about building excess capacity. What does this conversation mean in the regulated paradigm? Is it a problem to build some extra capacity? This is what the west did in response to the California energy crisis. Being exposed to the wholesale market, even if it was just 5% of load, was a disaster. The natural reaction was to mitigate that risk, build a little more, maybe develop a renewable portfolio standard. Build it, plan it, put the risk on the ratepayers. The entire time the regulator is doing this in the public interest because the alternatives in the market do not seem to be in the public interest.

Pennsylvania or Ohio looking next door to Kentucky or West Virginia that have cheaper prices. They're trying to determine what to do. They've started towards deregulation but they're not there yet and maybe they want to go back to that. That doesn't seem to be a problem.

If we consider completely deregulated states like Massachusetts, it's a completely different paradigm. They are a market player and have to follow market rules. Market power, whether it's a supplier or a buyer, makes a difference.

However, there's no agreement on whether restructuring is working or not. There isn't agreement in this community on the most fundamental issues of why prices differ. Studies by McCulloch and Ken Rose seem to suggest it's not working for prices, and that fuel costs are not the reason for the price differentials. There continues to be complete disagreement on the interpretation of the real world today. Without agreement on the fundamental realities, it makes it hard to have discussions that are based on that.

Finally, a simpler question. Is it a problem to have excess capacity in a fully regulated system?

Speaker 1: A good question that I'll try to unpack. In a monopoly regulated world the utility's acting, the regulator determines prudence, the customer pays. The customer doesn't get to decide. The question of monopsony really doesn't apply.

Second, states like Massachusetts can ultimately decide they want to go back to a fully regulated world. They have the power to get rid of retail choice. They still won't get cheap rates. Places like Kentucky have their cheap rates because they've got a lot of really old coal plants and Idaho's got really old hydro power.

Even if a state is going back to a regulated system they probably need new units, they're looking at carbon. Can they place that bet and hold it together when the market changes? Those are the choices that those states have to face.

Question: Suppose Massachusetts does do that. Can they start from ground zero and build back their equity again?

Speaker: Yes, but it's not good public policy. It won't lower rates, or provide benefits and they'd be sorry ten years later.

Another issues is if a particular state on the border of an RTO market decided to over build and sell in to the RTO at an unrealistic price the FERC might have concerns whether that was an appropriate market based rate from the predatory pricing standpoint. Rates can be assessed for just and reasonableness both high and low. If regulated states decided to tank an adjacent market that would be a problem, although it seems very unlikely.

Speaker: Is the premise to tank the market or to take advantage of the neighboring market?

Speaker: I mean minimize their exposure to the wholesale market, that's the motivation.

Speaker: After California's energy crisis the fear of exposure to the market pushed ratepayers to go along with the risk that they're buying a little too much. There are advantages for reliability too. If people get to sell into the market maybe they'd make a killing but FERC is addressing that with the western power tariffs. If one has market power they have to sell at a cost based rate.

Speaker 2: Some utilities went long energy historically. They would build a lot of coal units and didn't have a classic portfolio of base, intermediate, and peaking. This would occur with regulator approval because it would provide the lowest cost. However, it would be impossible for a regulated utility to propose to go long and build capacity over and above the least cost approach in their integrated resource plan if the plan was to sell power into the neighboring market while the customers pick up the assured cost and would get the rolled back benefits. That would not happen.

Speaker 1: I agree. Going long to prevent being exposed to an unpredictable and volatile wholesale market is possible. I could see this strategy in the northwest where there is hydro and they can't predict droughts so they might want to provide some reliability backup. Wind might pose a similar thing, it needs backup if it's not blowing.

Speaker 4: First, there are elements of regulation and elements of competition in all systems. There's no purity, nor should there be. Both are needed regardless of the organic state structure. The monopsony issue in ISO/RTO markets is fairly well settled law in both antitrust and from FERC. Below market pricing has adverse impacts on markets.

In regulated markets there may be an incentive to overbuild slightly, either via utilities or merchants, to stabilize resources, reliability, and shield from volatile regional wholesale markets like in California.

The merchant power plants by Palo Verde sited by the Arizona commission in the nineties helped keep the lights on during California. They helped keep rates reasonable and contributed to steady wholesale prices. When those plants went into bankruptcy, the ratepayers of Arizona didn't have to absorb that risk.

Question: If an RTO with a capacity market like PJM what happens if they over build. They're trying to reduce market prices to make power cheaper. Is it possible to be successful in that context? Does a substitution effect kick in that backs out private investment and gradually increases rate base investments?

With the capacity market, a new power plant is built and lowers cost. PJM calculates the difference between the capital cost for a new merchant investment and the energy cost has now gone up so it has to raise the reference price in the capacity market. If the only effect of the new plant was to reduce energy prices, and it wasn't participating in the capacity market then there'd be no effect at all because the prices would not go down in the aggregate. They would be offset in the capacity market.

If so, then the concern is what effect it has on the capacity market when it's bid into the capacity market. There it is targeted against peak load and it's not clear it has the same effect. It could be that it's both only partially successful or unsuccessful in lowering the prices. The benefits just aren't clear.

Speaker 3: There are two questions. How does this effect drive the interest in expanded investment in regulated generation? Two, how would this interact with capacity markets in the RTOs? Nobody's figured out the capacity market effect. There are too many complexities with timing, bid prices, etc. It could have a good impact if done just right but it is very risky.

There may be bad effects for long term investment. Does it drive all merchant investment from the marketplace? It might create re-regulation over an 80 year time frame rather than trying to buy back assets. Re-regulation through contract. It's very complex.

Comment: The demand curve variable resource requirement in the capacity market cannot swing the market substantially with a relatively small amount of megawatts, meaning 2,000 or less. Much more would be needed. If a state did that, then it's almost guaranteed whatever they decide will be wrong. It'll probably be wrong in the high direction and their ratepayers will be paying to float an uneconomic resource. The capacity market will only be affected by a large amount of megawatts.

As far as energy price that is different. With scarcity pricing and entry at specific times that knocked the energy price down, that would have a big impact. But then of course that does feed back in the capacity market.

Question: Let's consider carbon policy. Coal will not be getting built much, and it seems that natural gas will get built a lot. Speaker 1 discussed the fact that scarcity pricing and commodity price increases hit market environments more directly. It's going to be hard to build enough resources to serve the load so scarcity will be common. Carbon policy will lead to higher gas prices and more scarcity. How can competitive markets address this?

Speaker 1: In the 1970s and 1980s everyone assumed we had to mandate solutions and that is why the nation overbuilt in nuclear. They never saw the innovations in gas. Seismic, new resource discoveries, new turbine technology – they were all unforeseen. High prices in a market trigger a whole lot of innovation, one can't see where it's coming from. Command and control regulations commit us to long-term plans which may turn out to be very bad decisions. Although it seems clear, we really can't predict the future. Markets, and high prices, will force innovation, experimentation, without putting even more costly risks on the consumer. Everyone believes new coal and nuclear in the northeast is impossible. If so then gas is the logical choice there but put that risk on the investors. a non starter, you know.

Speaker: There's a reverse effect. Competition was implemented by the desire for $2 gas. $2 gas was cheaper than embedded coal and nuclear. The munis and coops were getting that, and the industrials wanted it. Ohio doesn't want to return to regulation. They want cost of service until the cost gets too high and then they'll look at markets.

A carbon scenario could impose huge costs on legacy assets and the cheap regulated states may not be so pleasant anymore. They want to hold onto the cost of the low cost legacy assets.

Question: Earlier someone discussed the "PJM monopsony tariff." It's actually a minimum offer price rule in the RPM tariff. It's not called a monopsony tariff for a reason, because it isn't. It doesn't require monopsony investigation. Monopsony behavior is extremely rare. Consider a sugar mill that is the only sugar mill in the area and all the farmers have to come to it. The tariff was specifically a minimum offer price rule that imposes a minimum price floor. I believe it is anti-competitive. However, RPM is not a market, it's an administrative construct intended to plug a hole in the existing market design. Statement number two.

Just like predatory pricing, it may be that monopsony power is more of a boogie man than a reality. Similarly, some antitrust scholars argue that predatory pricing doesn't really exist because it's not sustainable. Even if one lowers prices below marginal cost they can't sustain it long enough to get any benefit. Monopsony pricing has been discussed loosely by generators. I'd like your comments.

Speaker 1: Are you saying that monopsony pricing isn't a real threat?

Question: Yes.

Speaker 1: I agree that it would not be a good strategy for a state, or to protect consumers. I don't know why you would do it.

Speaker 2: If I said there was a monopsony tariff I misstated. My intent was to show language in the tariff that dealt with monopsony. I've been told that it was put in there because of fear of monopsony activity by load. Nonetheless, I don't think it's a serious issue. A lot of megawatts are required, and the payback period is too long. Nonetheless it's one more way in which people cast doubt on whether the markets work, or can work.

Speaker 3: I agree. However, quotes from states A and state B do have a chilling effect on the marketplace. They slow down those who would put capital at risk, and if they are pursued they will have a negative impact on the markets. There is a question of whether some states may pursue this sort of thing, even if we agree it is a bad decision.

Even more radically, I believe the focus on market power is misplaced. It was not the core cause of the California energy crisis. We have spent too many resources over mitigating and interfering with the markets. Less intervention would have been better, it has radically transformed how these markets function.

Speaker 4: There are competing interests between those who want mandated generation that yields potential benefits to wholesale customers and sending price signals that would ultimately disincent new investment and hurt markets overall.

Question: I'm in favor of markets but it's not clear that we have one that is truly competitive. Ours is in continual transition, like a third world economy in development. For instance, generators in New England market always talk in favor of competition but they want long term commitments to underwrite the capital costs of building generation. There are real concerns about natural monopoly or the degree of capital intensity that seem to reduce opportunities for long term investments. Ratepayers are on the hook for bad decision making but they are on the hook for bad decision making in the market too. Bad market investments come back to haunt consumers in the end. The ratepayers always pay. Can this really work? The uncertainty in California, Maryland, New England reduces market opportunities. If this system is an advantage, why haven't new states deregulated?

Speaker 1: World commodity prices for steel and concrete and gas and oil and coal are going up. Those costs will flow through to consumers. However consumers won't pay in the short run for over-builds. They didn't pay for the IPP over build when many investors went bankrupt.

Under regulation nuclear plants were built in an incompetent way at very high cost. Customers should not have paid for that. Some regulated utilities are not very good at it. Under competition the market would naturally consolidate so that winners would lower overall performance costs. Those benefits are real.

Long term contracts for new generation. Jurisdictions should consider an intermediate term strategy. 3-7 year contracts provide stability but the market is high now. That's another reason not to go 20 years for contracts now. Even if they would provide more guarantee that will allow private investors to finance and take more of the risk and do these bigger projects, make them feasible. I can envision nuclear capacity being built with the right portfolio of contracts. They are being proposed right now in Texas. We could be back into a downturn before a nuclear plant that was started today could even be completed.

Speaker: In the 1990s the customer did not take the hit. Once the shareholders of the IPPs took the hit, the capacity didn't go away. It was still available to the market at a much lower cost. The shareholders took the hit, and the customers got a real benefit.

Speaker 1: So why aren't more people doing it? Let's think about the analogy with the deregulation of natural gas. Gas prices today are very high, and nobody's crying for regulated price controls. When electricity was deregulated everybody thought it was going to be two cent power forever. However building new capacity requires prices to increase.

Gas deregulation came in because the caps were causing scarcity. No one could build houses in the northeast and connect them to gas because the price was too low. It was the reverse reason. Deregulation was phased in and nobody saw cheap gas coming and it did. Political acceptance occurred there because 15 years of declining prices. They saw that the market was working. In electricity the prices were going up and people were much more skeptical about the markets being able to work.

Speaker 3: You discussed whether we have a competitive market or is it always going to be evolving? A competitive market isn't a static concept, a nirvana that we somehow achieve and everything is done. It's a steadily evolving concept, and one in which many players have been learning. There have certainly been unexpected results and disappointments. folks are disappointed that retail markets haven't resulted in anybody calling you at dinner time to offer you a better product or a different product. I'd rather they didn't call me at dinner time regardless.

Retail competition hasn't worked in some degree because the wholesale SOS auctions are so competitive that there really isn't a margin for another product unless you want something green or with financial incentives. However the wholesale markets in Maryland, Delaware have 11-16 suppliers competing heavily to win bids. It's truly competitive.

It is an ongoing process. On flip side is the need for regulatory stability. These are huge capital intensive investments and one can't be just changing the rules every six months and chasing a two cent better price. There's a balance between evolving in a positive way and the concern for political uncertainty along the way. That's driven the interest in long term contracts. The capacity markets seem to be promoting generation and demand response investment; there's some movement in positive directions.

Speaker 4: Well in Washington there are always delegations who are simultaneously demanding changes and improvements to the RTO markets and complaining that FERC keeps changing the rules. [Laughter]

Question: This construct appears to be either you like markets or you want to go back to regulation. Deregulation was sold on the basis of cheaper prices and more choices. That did happen in telecommunications. There was no intent to deceive but not enough focus on the complexities of things like a capacity market, and getting all of the various components of deregulation straight. Expectations were for immediate results. We probably can't go back but there is opportunity for hedging, and it doesn't have to be all regulated or all markets.

States have to look at alternatives or hedge mechanisms to provide some stability and prevent uncertainty. How can that be done in a way that still lets the market evolve?

Speaker 3: Some customers got huge benefits through restructuring because of rate freezes. In Maryland it was 1.8 billion dollars of savings for consumers over 13 years.

Question: That was administratively structured, it's not a market.

Speaker 3: But nevertheless customers saw significant benefits that came as a tradeoff for restructuring. Even in California market pricing did drive prices down for a period. However, the message that competition would lower prices was absolutely the wrong message. It's hard to say that competition will provide lower prices than the regulated regime – that was the message that should have been given.

Competition has some good effects. PJM prices have gone up more slowly than the underlying fuel prices because of competitive pressures.

Finally, the types of actions that states have been looking at to ladder the SOS auction prices are beneficial. New Jersey recently closed an auction with a sizable rate increase but the overall rate impact was just a couple of percent.

Power prices are rising for independent reasons and it's important that customers respond to that with reduced demand and consumption. Obviously this is unrelated to the need to protect low income customers.

Comment: I'm skeptical that PJM has experienced slower price increases than the underlying fuel cost increase. I've seen no studies concerning this. I've seen other research that shows the exact opposite. This makes perfect sense because the underlying market design exacerbates the impact of natural gas price increases in a system that is predominantly coal and nuclear but with price based on natural gas.

Session Three.
Risky Business: Does the Current State of Allocating Risk Allow for Optimal Ex Ante Investment Decisions in Generation and Transmission?

Vertical integration of generation and load creates a portfolio of risks that can reduce volatility. To the extent that risks in load and generation are negatively correlated, the overall portfolio risk could be less than the risks of the components. Hence portfolio aggregation is a benefit of vertical integration in a firm. A cost of the portfolio is delegation of decisions to the central planner and, to the extent that there are bad outcomes, assignment of the risk to the customer. Unbundling and separation of load and generation addresses the problem of matching the locus of decisions with the locus of the risk, splitting the assignment between generation and load. And particle hedging through contract provides an opportunity to create hedges for load and generation, without the full requirements for vertical integration but at the cost of organizing the contractual arrangements. How is the allocation of risk working in the existing market structure? What changes are being addressed to revisit the allocation of risk and the choices that accompany the change in deciding who decides?

Moderator: I'm going to set the stage with a short discussion. Greenhouse gas emissions under a business as usual scenario go up very steeply. Various legislative solutions for this affect carbon CO_2 reductions somewhat differently but all of them develop a large gap over time that would be filled via conservation and technology reductions.

The UN Intergovernmental Panel on Climate Change, has looked at this gap. Among other things they demonstrate that a lot of money is needed to fill the gap, and a lot of technology has to be developed to reach any of these policy objectives.

Some of these approaches are negative cost technologies, primarily efficiency, they actually pay for themselves over time. Alternately, new generating technologies could be very expensive. Companies looking at various future scenarios and expansions are looking at decisions that may have absolutely enormous forecasted costs running into 2025 or 2030. There is enormous uncertainty for these models – in large part due to fuel price forecasts and technology ambiguity.

Carbon reduction is going to be a daunting job. Companies will need a big portfolio of options and they're not sure which are the right ones. Policy needs to create the right incentives to take advantage of the easy low cost options. Finally, long term rigid capital intensive decisions based on sketchy knowledge and fuel forecasts will certainly be wrong in some situations. So there's forecast uncertainty, technology risk, political risk, and decisions have to be made. So what's the best model? That's the lead-in to today's panel.

Speaker 1.

What policy options do governments have to get deployment of low carbon electricity supplies? I won't address the question of integrated versus diversified company structure. I'll focus solely on allocation of risk for building big generation supplies.

In December Congress authorized 38.5 billion in loan guarantees for building various low carbon energy supplies. The main sources for this are very capital intensive. They are primarily nuclear, renewables, or CO_2 capture. The government wants to incent the market to go after these things. CO_2 caps, production tax credits, loan guarantees all shift at least some of the risk to taxpayers. Which approach and mix of policy tools gets the objective at the lowest net cost to society?

I'll use nuclear as the example for a capital intensive generation. Not to imply that nuclear is better than solar or wind. A broad portfolio is necessary and everything has advantages and disadvantages. Nuclear carries with public bads and public goods that have to be addressed.

The models I'll discuss assume that nuclear is getting built on at least an occasional basis. Baseline models shows costs at $60 a megawatt hour for a regulated utility but almost $100 for a merchant plant because risk is on consumers for a regulated utility. This higher cost inadvertently suppresses low carbon capital intensive sources in a market environment. A higher cost of money creates incentives for a less capital intensive, more fuel intensive electricity source.

However, loan guarantees allow for restructuring of the financing. Instead of 50/50 debt equity the ratio can shift to 80-20. There's still a difference between regulated and merchant scenarios but it's not as drastic. It's around $65 and $50 per megawatt in each case with loan guarantees. Everyone expected nuclear plants to come into rate base but the first proposals are for merchant plants in Texas and this is probably entirely because of the loan guarantees.

What about a portfolio of options to create incentives for low carbon energy sources. For instance, loan guarantees and a price on carbon. No loan guarantees in a regulated utility model as well as carbon permits would make nuclear competitive to supercritical coal at maybe $6/ton for carbon. In the merchant environment without loan guarantees, it would not be competitive until carbon was around $20. However, nuclear would be competitive against coal in both a regulated and merchant scenario with loan guarantees, even with carbon at $2/ton or less. I should reiterate that these cost assumptions for nuclear may not reflect reality at all. Further, I'm just using coal as an example of a competitor, one could look at gas or renewables similarly. The main point is to get a sense of how these options function as incentives.

In the regulated utility, risk is borne by ratepayers, with merchant it's with investors, and with loan guarantees, it's borne by taxpayers. These risk allocations clearly affect the price, and affect how entities will respond to policy constraints.

Let's look at some of the unique risks that nuclear plants face. First, technology risk. These are plant designs that have never been built in the United States. There's been no new plants in the United States since the 1970s; there's no national experience with building them. There is a newly designed plant being built in Finland that's facing more than 18 months of delays and \$1 billion of cost overruns so far. There's been a very large increase in estimated costs in the past five years.

The experience of cost overruns in the 70s bankrupted some of the companies that were building these plants. There were large defaults, stranded costs, etc. There's limited capacity too. There are key pinch points in the global supply chain. There's only one company in Japan that can make the large steel forgings and they have a three year backlog. This can drive up price because those companies can ask more or less whatever they want.

There is also regulatory risk. There is an new untested Nuclear Regulatory Commission combined construction and operating license approach. It was designed to reduce the regulatory risks by making sure that once a company spent billions of dollars building a plant they didn't have to ask for an operating license afterwards. However, this new policy has never been used before and no one knows how long it will take and how successful opponents will be able to function within it.

There is political risk. You've got positive opinion but it's been a long time since a plant was built. The real strength of the anti-nuclear forces once they really get going is unknown.

There is potential long term spent fuel liability. Some players say it's not important because it can be stored in dry casks for a long time. Others argue it's important to local attitudes about nuclear plants. The risk from accidents and terrorism is limited by Price Anderson which caps liability but it's still a factor. If there is a major accident or attack not only in the United States but anywhere in the world, it would have a huge political impact on the ability to finish a project. Even if it were halfway finished with a lot of expended capital.

Congress has four primary strategies for low carbon generation. Production tax credits don't kick in unless the project succeeds and starts generating. It's very helpful for projects with modest risks but high costs, like solar or wind. Solar and wind folks are focused entirely on the tax credits, not loan guarantees. The nuclear people are the ones obsessed with loan guarantees. Tax credits are costly if they're done throughout the life of a project.

The second item is insurance for regulatory risks in the Energy Policy Act specific to nuclear only. It doesn't handle other risks and it only handles regulatory risk.

Third are these loan guarantees. There was 38.5 billion in the omnibus appropriation with 20.5 billion specifically for nuclear. Firms receiving the guarantee pay the subsidy cost; the estimated cost to the government of providing the loan guarantee. If the government does its numbers correctly to estimate the risk, there's no cost to the taxpayers in principle.

Fourth is legislation for carbon cap and trade and other carbon legislation. All of this is still being debated but most people expect we'll get carbon prices one way or another.

There are a wide variety of questions to consider in all of this. Why can't the market do loan guarantees? It is essentially default insurance provided by the government. Well, most major investment banks won't provide financing for nuclear plants. They can't assess the risks and price it. Other firms price it so high it could never get built. The guarantees make the government take on risks that the market says are unknown at prices far below the market rate. It's really not clear whether this is good or bad public policy.

The market is adequate for the lower risk technologies but then one questions whether nuclear should get special treatment. I'd argue Congress shouldn't be allocating specific amounts for each specific technology – they should compete against each other with the same guarantees.

Another concern is nuclear projects are getting to be so gigantic that a generation company is betting a large fraction of their total market cap on one project unless they have a lot of partners.

So what set of policy tools will lead to deployment of low carbon electricity generation at the lowest total social cost? Does the U.S. just jack up the carbon price until people start deploying these things? Should we mix carbon prices and loan guarantees, or carbon prices and tax credits? What is best for the overall economy? What's the least distortionary? Do loan guarantees for specific technologies inherently distort the market and lessen the attractiveness of other options? For example, what about loan guarantees for efficiency which is clearly the most cost effective approach with virtually no risk. How much risk of major default are taxpayers taking on for the different technologies? Is DOE the right entity to administer this? In the 1970s had 12 out of 14 loans default. I'm told DOE has now hired some capable people from real markets who understand risks and defaults but we'll have to see.

Another question. Do loan guarantees get the first of a kind plants built and buy down the risks of new technologies. Or will they continue to be used to support subsequent builds because these projects are so capital intensive? Should subsequent guarantees be technology neutral to let the market fight it out in terms of which technologies should get built? I would argue for that.

There is a risk that the government spends all this money and the plants are still uncompetitive in the end. This is quite plausible, particularly for nuclear. What other policies could governments use to make capital intensive low carbon technologies more competitive? Further, what policy tools should be applied to get adequate deployment of electricity infrastructure beyond generation? And a third question, are loan guarantees an appropriate role for the US government in promoting low carbon sources in other countries? Ultimately, we don't care where the carbon stops getting emitted, just to reduce emissions on a global basis. Loan guarantees are already available from the vendors when US companies are trying to build a plant overseas. For some technologies three is financing available from the multilateral financial institutions. However with Ex-Im Bank financing, the public good being supported is more export led jobs than low carbon. One can get Ex-Im Bank funding for a pulverized coal plant as well as a low carbon plant.

Speaker 2.

I'm going to focus on uncertainty and how to find the cost of capital to apply in uncertainty. The session description describes contracts of vertical integration that transfer risk from generators to consumers. In Europe the risk can be transferred without a contract. Competition authorities would prevent an incumbent from having long term contracts with consumers. It's considered an abuse or attempt to create monopoly power. At the same time economists argue those contracts should mitigate market power. It's a contradiction.

The risk aspect of long term contracts does not merge well with market power. Forward contracts mitigate market power, reduce uncertainty, and induce investment. However, one actually gets ambiguous results when there is effective market power. These are generally hard to analyze, even if market power is not present.

The market is facing enormous risk right now. Both fuel and demand risk have increased drastically. Competition adds real risks. There is regulatory risk. There are always problems to solve in restructuring and the process of fixing those things creates uncertainty. In both the EU and the U.S. there is uncertainty around carbon and climate change mitigation. This includes concerns for carbon leakage in regions with different rules. and is in fact testing some new policies although the consequences are not really known. Finally, the environmental risks also create large technological risks because so much technological progress is needed to satisfy the carbon goals.

Some have argued that we don't need to be concerned about risk. We put it on the industry, it's used to it so it can manage risk, it has done that for several years and it can still do it. If a company goes bankrupt simply transfer the ownership of their plants to other owners. The subprime crisis has shown us that this is a simplistic view. Some argue we can just go to the derivative market but those products are not traded for a sufficiently long maturity. They are not liquid enough and generally incomplete. Other approaches like CAPM need longer and stable time periods which do not exist in this industry. Corporate Bonds need decomposition into trenches which cannot be done.

One approach is to begin to apply cost of capital in a project specific manner rather than to a company overall. We need more information on the cost of capital for different plants. Further, risk analysis needs to address the fact that past cost of capital for a company is completely unrelated to their future capital costs. Finally, the market design has an impact on the cost of capital. This is more subtle. Market organization can create or mitigate risk.

To look at this we've constructed a stochastic equilibrium model that is similar to the market. It's not an optimization model that people use to plan their investment. We assume agents are risk averse in a way similar to real-world practice. Fuel risks and carbon risks are explicitly represented. There is an implicit target of $90 per ton of CO2 which apparently the EU will try to manage by manipulating the market. Obviously $90 or $30 for a ton of CO2 makes an enormous difference.

Depending on the country one invest in gas or coal depending on which plant is making the margin. Gas plants in countries like Spain or Italy where gas is making the margin but coal in Germany. That influences the portfolio.

The economic model stylized and computable; to see revenues, costs, and extendable into something realistic. It allows for a capacity market and an energy only market. There are six different models of the carbon market based on the most recent ETS legislation in Europe.

12 scenarios are created. Investment is rigid and decided before uncertainty is resolved, before one knows what is going to happen. There is not much of a portfolio effect that happens. There is risk of bankruptcy in those things. Most often if the coal plants are profitable the gas plants are also profitable. The cost of carbon tends to equalize the performance of the plants. You are changes in merit orders depending on scenarios but generally gas and coal do well simultaneously. However, there are several scenarios with losses on both types of plants.

In the European context, with different policies in various countries, and bottlenecks between the countries, then one can still build coal in Germany or gas in Italy and Spain and expect to do reasonably well

In energy only markets the risk premium are much higher. We modeled energy only and capacity markets with price caps at 250 and 1000. In all four scenarios, the risk premium is generally better for coal. Higher price caps reduce the risk premium and make gas and coal much closer. Finally, with a capacity market the risk premiums drastically decrease.

In the EU there are no capacity markets. In some sense companies there get rid of the risk by transferring it to the consumer by not building and perhaps allowing for some shortages. This underscores the fact that market design has significance.

This modeling doesn't account for different kinds of contracts. We just look at the kind of risks implied by different plants operating in different circumstances. Conceivably, contract design could have a strong impact.

There are some other concerns. We understand very little about the reaction of the consumers. There is the problem of carbon leakage. Energy intensive industrials and consumers argue they will move out of Europe to avoid higher carbon cost electricity. Particularly for steel, aluminum, and cement.

Some companies assert that one should apply standard corporate finance for investment. Standard CAPM analysis runs into really technical problems because of the constantly evolving nature of the industry. Second, risk premiums are changing constantly. Third, we know very little about demand response. This makes good assessments very difficult.

Making good market assumptions about investments is extremely risky. If you combine all the uncertainties coming from restructuring and from those use policies, it may be the old system is better.

Speaker 3.

I'll consider much of this problem from the perspective of large industrial consumers of energy. Ultimately the consumer pays for everything. In the old vertically integrated world consumers disliked the lack of efficiency in the overall supply system. In particular incentives for one control area to trade with another control area weren't there. Consumers also disliked the allocation of capital decisions, in part because they had no say.

In the new world those two things remain as problems. While investors do take risk on merchant plants, ultimately the price risk when a merchant plant goes belly up rests with the consumers. Consumers still bear price risk for decisions made by independent entities. Consumers want a say in those risks, and they want just and reasonable prices.

Current market designs are dysfunctional. Let's consider the one subsidiary of the Allegheny Power System, Potomac Edison, that operates in both Maryland and West Virginia. In 1998 pricing was around 3.1 cents per kilowatt hour for both states. Current pricing in West Virginia is now 3.8 cents a kilowatt hour and in Maryland it's just under 7 cents.

The difference between those prices is market design. It's driven by the difference in the way the market is designed versus the underlying actual cost structure. It's not a tenable situation.

The goals are long lived capital intensive investments and reasonable risk allocation between the developer and the consumer. The previous speakers pointed out that the cost of capital is significantly different and reduced by certain guarantees. The use of long term contracts in other businesses creates investment certainty and that's what we're missing here.

Here are some proposals for a new basic market design. Let the ISO be a risk aggregator and develop a long range, integrated generation, transmission, demand response plan. They should then do long term forward capacity procurement. Then set up a call option structure with a FERC backed tariff that assures long capital recovery for the generation developer. This means that the energy comes out of those units at essentially cost.

There are more elements to this market design. The long term structure is critical whether it's a contract or a FERC approved tariff to mitigate risk for developers. Since there's long term capital recovery mechanisms it gives longer term price stability for consumers who are bearing that risk. Today's markets reprice all old plants at today's cost and that's a real problem – paying gas prices for two cent hydro. I'll address further questions later.

Speaker 4.

There's enormous risk and volatility facing the industry. Fuel costs are clearly going to go up, and have a lot of volatility. Not only is there volatility but scarcity is real. There is extensive volatility in electricity prices themselves and also in congestion. In the short term electricity and congestion prices are more volatile than fuel costs. Long term fuel costs are highly volatile. I expect this volatility will be amplified in the future.

There are other added costs to the system. We can consider historical rate volatility, fuel volatility but also construction costs, environmental volatility, and demand volatility, and finally technology variation. There may be some diversification of risk but the market is fundamentally riskier than in the past. Innovation may be the saving grace as it can actually reduce risk at least in a broad way. The market design that we employ has a big impact on whether the market innovates.

We can consider generation, distribution, and consumer segments of the market. All of the various risk factors affect each segment. The question is how should risk be allocated for the best market design with long term economic benefit to the consumer and the industry. The risks within that system are constant independent of how you reallocate it.

An investor will look at the risk they can't diversify away, that requires a risk premium. It's the basis of portfolio investment theory. Ultimately, retail and generation can have the risk diversified by investors. However, a consumer can't have their portfolio diversified as easily, right? They're not part of someone's investment portfolio. So there are constant risks and the question of how to move those risks around.

Initially one could say that both generation and retail can just push those risks onto the consumer. However, that's not entirely the case. For instance an upwards spike in volatility driving prices up will lead some generation with base load benefits to depress a bit when prices finally drop again. Retail can't always pass on risk costs to the consumer in real time. Some argue that if you combine generation and retail then it will cancel each other out and lower risk because when one is going up in generation the other one's going down in retail. Investors still see the overall risks to the industry however, and that's what matters. Those non diversifiable risks are simply additive.

In the late 70s, early 80s there was a conglomeration fad where people like Gulf and Western made a case to Wall Street that one should buy their stock because they were buying a bunch of companies to diversify their cash flows, they're a better investment. Ultimately one got a bundling discount and there was actually risk benefit in keeping them apart.

If an investor was to combine these entities together the fundamental risks are external to that system, right? Then one could hedge risks and hedge yourself to the gas market, the externality, not the internal system itself. However, surprisingly few vertically integrated utilities have been fully hedged on the gas front; maybe 40% at most over the last five years.

Perhaps combining these entities gives a benefit in terms of cash flow. However empirical studies don't show that. During the nuclear build-out the costs were about $100 billion, about 150 billion in 2005 dollars. That got passed through to a large extent to the ratepayer. With gas in the late nineties we're looking at about 40 billion in costs that were borne by the investors.

From 2006 to 2030 some people estimate there will be 258 gigawatts of added capacity with a very high fixed cost. What industry structure will give us the least likelihood of facing a 150 billion or $200 billion loss? That's just on capital efficiency.

Operating efficiency is important also. Data looks at decentralization between generation and retail, investor operated utilities that are integrated, and co-ops and Munis. Labor and non fuel expenses are a bit higher when they're vertically integrated on average, we don't seem to gain efficiencies for combining generation and retail in a regulated system. So combining these entities in a market environment or a vertically integrated environment doesn't work in either case.

Further, the unbundling of wholesale and retail exposes important information about uncertainty that is essential for good investment. Contracts between generation and retail gives the market good information about the price going forward and uncertainty. It tells you a lot about how you want to bet on different generation solutions going forward. Without that one can't make a good investment decision. Without uncertainty there is no investment community; it's all government bonds, right?

Having that distribution of information, that uncertainty is critical for people to place different bets. Those bets won't all be consistent. Everyone will have a different point of view and that's fine. To effectively employ that a decentralized marketplace is needed, to create a variety of different investment options. Having multiple generating companies is very useful for this.

So one critical element to innovation is uncertainty and the information around it. The next key thing is creative destruction. Many of the multiple bets will fail, some will work – that's the way industry moves forward, through creative destruction. Vertical integration is a good obstacle for creative destruction, particularly as a monopoly.

In research by James Utterback at MIT, he showed that if you look at a host of industries, you can see certain patterns. He looked at disk drives, personal computers, and the automotive industry. During the period of innovation a host of people come in placing multiple bets with different potential views of the future and only a few are right. The winnowing down of multiple bets that creates innovation and different business processes that improve the economics.

His data also shows that innovations over time corresponded with the amount of companies in play. For the utility market the last period of great innovation was back in 1926. [Laughter] In 1926 there were over 8000 utilities and it's been flat at 3,500 since the 80s. This is not an innovation pattern. Uncertainty is what prompts a great deal of innovation.

So we need uncertainty that we can see in the marketplace. Currently the average lifetime of companies is the S&P 500 is around 15 years. It used to be 70-80. There is only one company left from the top 10 companies in the Dow in 1896, that is General Electric.

My worry is if we embrace an industry to protect it and keep the risk down we'll smother it. Martin Feldstein has argued that cell phone service in India today is widely available in India at low cost because it was regarded as a luxury and therefore left to the market. Alternately, electricity is hard to obtain because it was regarded as a necessity and therefore was managed by the government. This is worth thinking about. This is strongly related to whether we conceive of electricity as a commodity or a necessity.

The market for information for these companies has to be reasonably open and diverse. There are generally reasonable rules around that. An open and diverse market will provide the best forecast of uncertainty and prices. People by their nature are miserable and irrational when investing. They're more than two and a half times more sensitive to down side than up sides and sell winners too quickly and hold losers too long.

We think of the electricity industry as being very long lived. Further, it's hard to have a lot of adaptation with big heavy assets. However Charlie Fine, also of MIT, has looked at product life in different industries. This is the life of any given product whereas process life is the amount of time to measure improvements on an existing dominant design of a product. Generally process life doubles that of product life but the electricity industry assumes a much longer time frame.

When we think of the energy industry everyone assumes it is a very fixed cost business. That is just not as true as it was in the past. The industry has a lot of information that drives its economics whether it's how you manage a network or demand response. This information component goes beyond assets. The industry would benefit by not overly committing to reduce its risks. As soon as they over commit to lock in, they reduce the ability to flexibly adapt and gain competitive advantage. Darwin notes it's not the strongest or most intelligent but the most flexible that will survive.

The industry can benefit by reducing its really long term commitments. There are other industries with enormous investments that don't necessarily work with long term commitments. For instance, computers, air frames, microprocessor fabrication. They are very risky with investments at the $12 billion range to build. Even things like casinos cost $3-4 billion. They are risky, without long term commitments, and are able to innovate.

So what do we need? Segmented accountability between wholesale and retail is a good thing. Market prices and uncertainty for innovation. A diverse range of investment participants with experts and non-experts alike. That is happening now to some degree.

An exchange would really help facilitate the collective behavior of investors and introduce liquidity to the market. It allows for clearing and can let investors address congestion and other risks effectively.

There's been extensive growth in trading with the ISOs. 40-50% over the past four years or so. Gas is important because you need longer term contracts on electricity and gas simultaneously. ICE also has more and more liquidity but that builds up over time going from the short term to the long term. The bottom line here is that exchanges are a chicken and egg problem. Nonetheless it's clear the markets have been building up liquidity slowly.

Question: Speaker 3 stated that price risk for merchant plants going bankrupt was on the customer. I'm confused by that.

Speaker 3: Market price risk doesn't capital components. The risk to the consumers is if there's not enough capacity and prices go up then the consumer bears that risk. In cases where there's excess capacity those new units weren't necessarily even being dispatched. The ones sold at a loss were excess and were not affecting the price to the consumer anyway.

Question: The new plants were far more efficient than the existing plants. Some with 16,000 btu heat rates. We really need to see more detailed analysis of this.

Speaker 3: I always try to do this kind of analysis. The market design is still producing significantly. The revenue requirement under the old system for the PJM system relative to today are much greater. It seems like a tax on electricity consumers in PJM. It is a wealth transfer from consumers to owners of generation. Some generation owners are making 30% ROE on their PJM fleet.

Question: The allocation of risk to different parties changes the decisions that they make. Additionally, the allocation of risk for different parties has cost effects in and of itself. The total amount of risk in the system might actually change under different schemes. as one speaker suggested, if it makes things better then it's good to do it in a more decentralized way.

However, there is the concern for the status quo bias. Most everyone would agree an IRA is good. If a business tells their employees they can get the benefit if they register ahead of time they get maybe 35% of their employees to sign up. If it's an opt-out situation then about 98% sign up. It's behavioral economics and the status quo bias question. The same thing is true in electricity consumption; particularly for small customers. So a vertically integrated firm could have implicit long term contracts and hedges – they're just there. Then generation and retail are unbundled and retail customers are let loose on the spot market. They can contract around to create a hedge in order to reconstruct what they had before. This is apples to apples. However the customers don't contract for a hedge because they have to opt in as opposed to opt out. That's actually happening. The difference between Maryland and West Virginia may be this difference to some degree. So the market design may create real difference in terms of behavioral economics. This may raise the total real social cost of the system. It's a market failure in the behavioral economics sense and it could make a real difference.

What is the accounting framework to resolve this question ? How do we address this problem?

Speaker: Your first narrative in which risk stayed static and there's just exchanges seems more accurate to me. One aspect you didn't mention is that bankruptcy costs can created added cost to the business. It's better if companies are acting prudently and bankruptcies are not a common element.

Customers become trained to some degree to pay attention to prices. That's the assumption of demand response. If we start with customers facing a real time spot market price then savvy, profit-oriented retailers provide solutions against volatility in different ways. It's in the retailer's interest to close the gap for the consumer. It's better for the retailer if they aren't burdened by the simultaneous need to maximize their profits in generation.

Question: I understand the concept that the risks are similar in the two systems. Isn't one of the big differences that when you have a utility you will always get a lower rate of return. The risk isn't monetized in that case, or the same with loan guarantees. The people who are making the decisions aren't seeing that cost.

Alternately, loan guarantees are a subsidy that bias towards a technology choice. If they had to pay the full cost of the risk they probably wouldn't go forward. However, it does cost more because there is uncertainty around the outcome.

Speaker 3: They are a subsidy that could screw up investment decisions. The preference is decided by government. The current market design may be increasing risk and thus increasing prices. That's a problem.

Speaker 2: The distribution of risk in the old system was passed to the consumer. Now the risk has to be redistributed. Some parts of the market are in place to make this work but other parts are not developed. There are transaction costs, or information asymmetry. Some of the financial products being sold are extremely difficult to understand.

If the system doesn't appear to be working because some parts aren't developed or there's market power then people will not trust the trading of those product. As soon as the organization of the system is changed then the possibility for reallocating the risk is there. First move the risk to the generators. As soon as you move out of the vertical integrated system, then the market for risk develops well or not. Probably not very well because those structured products are very complicated.

Speaker 1: Nobody knows how to assess the net social cost depending on the risk. The loans can be a subsidy although I had mentioned if it's structured so the government does its numbers right there should be no net cost to the taxpayer. The numbers I had were from the Nuclear Energy Institute that had the subsidy cost at 5% of the value of the guaranteed debt. That is an extremely low probability that the loan will default and it's probably wrong. If the subsidy fee is 10-20% of the guaranteed debt then it doesn't look attractive any more. If one implements the real risks of default on a huge untested nuclear project of this kind then the difference between the guaranteed and unguaranteed cases is going to be much less than I discussed earlier.

Question: The complex risk problem presents the opportunity to think about alternative solutions that are not necessarily vertical integration and having the retail company own the generation.

For instance, the New Jersey basic generation service auction has attractive properties this way. First, it's an opt out system; one needs to elect not to participate. Second, they change the definition of the product from owning the generating plant to having delivered energy. This allows very complex transactions in an explicit contracting framework but still ensures the customer gets their delivered product

Speaker 3: The only problem with the BGS auctions is the pricing reflects flaws in the underlying wholesale market design. If the design is flawed then the resulting costs to consumers are still a significant problem.

Question: The concern is not whether to have a market, it's having it designed properly. That would still accommodate the separation between wholesale and retail.

Speaker 3: Yes. The wholesale market design needs to be designed better.

Speaker 2: First, does the market create different types of risk? Second, how is risk traded? They are two different questions. The intersection between the two occurs because market design creates products that have to be traded and the risk associated with those products have to be traded. One should keep the two problems separated. So you generate more or less risk depending on how you organize the market, and then given those risks you have to design the way to trade them.

Question: The consumers had an implied hedge in the regulated world, and utilities had an implied contract with customers. The problem was the contract did not actually bound the consumers. In the mid 90s, some utilities had a cost under a contract that had to be recovered and yet end use customers said I want the cheaper power.

We still have customers who aren't parties to the schemes. They have intermediaries or representatives. BGS is short term contracts with opt out so they don't bind the customer very much. Their representatives have negotiated market design issues as well. The only way to get to a world of innovation is if all the consumers are engaged in the market. They have to sign up for power, tell the utility when they're moving. There's a consumer engagement element that's missing.

Speaker 4: Well, I agree. [Laughter] Electricity is a quasi commodity today. It's an industry with a desperate need for innovation that needs the consumer involved so people can innovate and fail. Innovation will change the product so consumers should start paying attention. It's not a huge burden.

Question: It's their responsibility.

Speaker 4: Yes. However there's a tendency to go back to thinking of it as a regulated necessity.

Speaker: In telecommunications deregulation in the 80s if one failed to choose another supplier through the ballot process they paid higher prices. They only got lower prices if you chose.

Question: I'm interested in the nuclear renaissance. There are some strong reasons for the delays in the nuclear plant in Finland that were discussed. Problems with the licensing process. There is a second plant being built by EDF that is doing better. It is on budget and on schedule. A third project is in the works so some of these companies really do have some good nuclear expertise.

My understanding is the loan guarantee program was never intended to be a permanent feature of the US nuclear industry. Does this make a difference?

Speaker 1: The analysis I did seemed to show that even after first generation plant construction, the loan guarantees still seem to be needed in order to be competitive with higher carbon sources. It's a real question whether its first generation or more than that. On the other hand if loan guarantees are implemented for a second round it becomes very easy to create an endless cycle of this kind of government support and that may not be appropriate. However, they may have an non-monetized public good aspect to them.

Question: Have you examined the price of new nuclear compared to the price of other base load generation? It should be competitive with carbon by 2015 given the costs of carbon capture and carbon emissions.

Speaker 1: One can trade off between reducing the cost of capital or increasing the carbon price. If you raise the carbon price high enough then nuclear will be competitive. Or one can have a low cost of capital and then the carbon price doesn't have to be as high for nuclear to be competitive. It's not clear what the total social cost of those two options is.

Question: There are a lot of competing studies that show values or losses in restructuring. One speaker distinguished between capital versus operating efficiency. If we unbundle the system it will encourage transactions costs of doing the contracts.

The first two speakers between capital and operating efficiency. The benefits of unbundling with operational efficiency and innovation don't show up in the models. It's really not clear whether these advantages exist, and all the studies give us different results. Can these issues be resolved? If operational and capital efficiencies don't exist then one could just tell DOE to build the next fleet of nuclear plants. [Laughter]

Speaker 1: DOE has never brought a commercial scale plant of any kind to fruition.

Question: So there must be operational and capital efficiencies somewhere in the system. [Laughter]

Speaker 1: My analysis didn't look at this problem. It assumed the same capacity factors and other issues for the plants. There are definitely other issues that could influence the results.

Speaker 2: This is a very difficult question. There are different contracts with different incentives for efficiency. They exist in transmission and distribution. In those regulated activities a portfolio of contracts has to be offered. In the market one sees fixed price contracts, or contracts with different indexation clauses. These can incentivize a company to be efficient. It is difficult to quantify their effects.

Question: Many of these studies assume no efficiencies depending on these contracts. They look at risk or changing the capital structure so that the risk changes and the same operating efficiencies still exist. However the operational and capital efficiencies really should be accounted for.

Speaker 1: Nuclear plants have pretty similar capacity factors and related efficiencies in both regulated and market systems. It may be that restructured markets had an incentive and got there first. Then the regulated plants saw what could be done and followed along. There may be a causal externality there for some states that began in the market environment. In any case, high capacity factors in nuclear plants also occur in regulated systems.

Question: Yes. Regulated markets changed the incentive structure for regulating the nuclear plants. It's not just unbundling it, but getting the incentives right.

Speaker 1: Which is key, whether it's unbundled or bundled.

Speaker 4: A lot of these issues are infinitely debatable, and we don't have extensive firm data. There are other elements to consider in thinking about what's the right structure.

The incentives are clearly visible with the separation of generation and retail. We tend to see specialization in other industries rather than bundling. Innovation is masked within a vertical structure. Information, the ability to try new things get dampened, and failures get limited in that environment. What allows generation investments to fail and new ideas? How correctly are prices and risks being seen in the existing structure? There's a lot of faults certainly with the existing system but I don't see a better alternative to deal with the risks and the need for investment in this industry. The contracts aren't there, they'll add a cost that should not be significant but there is uncertainty in that.

Speaker 3: The problem is when there are operational efficiencies out there, the benefits are all accruing to the generators because of the current market design. We have to separate risk issues from the market design but they're also linked. To a large degree the marketplace design is creating incentives for low risk alternatives.

Moderator: To clarify, are you worried about existing plants making a lot of money, that the industry will not build the right mix of plants? Do we change the market design? If we do the efficiency of the plants may go down significantly.

Speaker 1: I'm concerned about both. The current market structure doesn't support some of the type of risk taking needed. Some generation fleet owners are earning huge transfer payments. And the lack of investment in innovation is a concern. The big generation owners are not doing innovative things.

Question: I'll address the West Virginia Maryland dichotomy. In a regulated monopoly the risks are socialized to some extent. It doesn't fall equally on all the customers. The large industrials have the ability to arbitrage between market and regulation. They may use that as leverage to stay, or move their operation to Mexico. The comparative numbers between those two states doesn't reflect exactly who's bearing the risk. The greatest risk is put on residential consumers in the least position to manage them well. In a market there are similar inequities but the investor is taking bigger risks.

Speaker 3: Well, the same chart could be drawn for residential customers of the same utilities in West Virginia and Maryland and the cost differentials would look the same.

Question: Until the industrials leave West Virginia and go to Mexico. Then it's different.

Speaker 3: All that's going to do is throw more costs onto the residential folks.

Question: Exactly.

Speaker 3: The current market design creates the incentives to flee to Mexico. The residential customers get hurt worse because they have no ability to do anything. Large industrials have always had some choices, more than residentials. The differences between the two systems is the same for all customer types.

Question: Except if the industrials leave in market, then the price will go down. In a regulated market it's the opposite. Demand disappears and the remaining demand pays more. The smaller customers are bearing a disproportionate amount of the risk.

Speaker 3: Well ultimately there is load growth everywhere. I'm skeptical that small customers ever actually see the benefit of one large steel mill or cement plant having closed. People in Frederick, Maryland didn't see any benefit when Alcoa closed its plant and shed and 180 megawatts of load came off. It didn't lower prices because PJM is such a big system. It may have decimated the town but it didn't change the pricing.

Question: If it had been a regulated system and a local monopoly, the price would have gone up.

Speaker 3: Industrial customers want market reform, not reregulation. The markets are not truly competitive and that is what they really want.

Question: A large fraction of the states do not have full restructuring but have aspects of competition. Colorado relies on competitive bidding for longer term capacity contracts. Can regulated or hybrid states implement actions without going to full restructuring?

Second, in terms of innovation, might regulated states be free riders? They won't necessarily incent innovation but they'll get the benefits spread to them.

Speaker 4: Regulated states should get the information for making investments out there. The free rider problem does exist. In the northeast some hubs are more liquid than others, so traders will hedge on PJM west when they have a northeast risk because there's no liquidity in that hub. Getting available information is critical. Some will be polluted to a degree. If they're hedging northeast risks with PJM west there is congestion and loss risk that can't be covered.

The information gap is quite relevant. Distortions between regulated opaque states and transparent market states affect investment decisions concerning fuel and electricity. There are reforms to the markets which would help a lot. I'm a big defender of the current market system but more of an energy only price structure would create better information.

Second, regulated states need to ensure consumers respond to prices. Peaks are critical and capping them hurts the economics. Real consumer response allows the economics to work properly in both systems.

Question: In the 1990s industrial customers in New York noted that market prices were two cents and Niagara Mohawk's average generation cost was six. They argued that utilities were incompetent and we should go to a market. Fundamentals, discussed by one of yesterday's speakers, were at work then and explained the differences. Ten years later the exact same fundamentals are at work only now gas is high, new capacity is more expensive than old, and there are shortages so there's pressure to build. Markets are working as they should but exactly in the opposite direction.

The fundamentals are simple, and yet we hear that no market in the country is working. They are. Certainly there are load pockets or a need for long term transmission rights to hedge. However, the markets are fundamentally working properly. They are consistent with the fundamentals: the market price is set by gas and it's very expensive now. They are priced at marginal cost, that's how markets work, and that's what industrials wanted in the 1990s.

You asserted that consumers want financeable long term contracts or FERC approved tariff based recovery for new and necessary resources that assure returns to investors but also provide price stability for consumers. This sounds a lot like old style integrated resource planning, a central authority making all these decisions about what's the right thing to do with resources and then guaranteeing these recoveries of cost. Do industrial consumers want to go back to regulation?

Speaker 3: They probably want it more than the current market structure. The material that speaker 1 presented tells you why. Guaranteed revenue recovery lowers the cost. A nuclear unit in a merchant world at $90 and a guaranteed recovery unit under regulation is $50, it's a huge difference. Electricity is a commodity that's very different than other commodities. I can't concede that this is how markets work. It's not how markets that I've operated in outside the electricity industry work or are priced.

Question: I agree the arithmetic is irrefutable in the calculations from Speaker 1. What happens in that world is that if that nuclear plant turns out to cost ten times more than was promised the consumers still have to pay. In a market world if a generator builds that nuclear plant and it's ten times more they are out of luck. They have losses, or maybe go out of business. Consumers want that cost based rate when it's cheaper but as soon as the market's better they want that. They need to commit to one system or the other.

Speaker 3: My reforms require that if a generator says they can build a nuclear plant for X billion dollars and they contract for it then they are committed to that capital recovery number. If they have cost overruns the construction risk is on them and because it's backed it's still going to get closer to the cheaper $50 cost than the $90 cost.

Speaker: There are opportunities to reduce the risk to the investors through long term contracts. That's occurred worldwide not only for nuclear but for various other things.

Speaker 3: That's the solution in Romania. Have EDF build a nuclear plant and manage risk via long term contracting and reduce the carbon footprint too. Part of the problem is a lack of competitiveness in the markets that the current design exacerbates. In NYMO the difference between cost and bid based was a 25% increase. PJM saw a similar thing in 1998. The current markets and market design don't allow for fluid competition.

Speaker 4: I don't agree. Perhaps the rules could be improved but it's not a market power issue. It's hard to know if individual bidders are bidding more than their true cost. Generally investors are terrified of market power problems. It is a death knell. They can't do forecasting and they consistently lose. They are like a canary in the coal mine – if they start dying off then we know the markets are really not working.