Harvard Electricity Policy Group
Special Session

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RAPPORTEUR'S SUMMARY*

Session One: Spotlight on the Board: Governance

Corporate governance is a hot topic. RTOs are not an exception from that discussion. It is hard enough to define roles and responsibilities when there are shareholders and a stock price. What should we be learning about governance of a new best like an RTO? California began with a stakeholder board, but has now discarded that model in favor of a board appointed by the state's governor. Other RTOs have employed a model in which the directors are independent persons who have no formal connection to any market participants. To whom, however, do these directors owe their primary duty? Are they fiduciaries for all of the stakeholders? Are they the protectors of the consumers, or the guardians of a broader public interest? How are the incentives of the directors aligned with these goals? Are the directors a self-perpetuating group, or should stakeholders or regulators have some say in their selection? How do stakeholders participate in decision-making under the board? What procedural rules guide or constrain the board's activities?

Speaker One

We've created regional transmission organizations that are really a kind of hybrid agency. Let's start with FERC Order 2000's three basic criteria for RTOs in terms of their independence. Neither employees nor board members can have a financial stake in any of the market participants within the region; the decision-making process needs to be independent of the control by any individual or class of market participants; and they need the independent authority to propose rates, terms and conditions.

I want to raise several questions about RTO governance. Obviously, when you think of a board of directors, you think about fiduciary obligations. The question with an ISO board is: to whom are those obligations owed? Another is, what is

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their obligation to stakeholders? Assuming they have an obligation to listen to stakeholders, how does that play out? What if the decisions that RTOs make are divisive among stakeholders with different opinions? Exactly what is the fiduciary obligation owed?

What about FERC? It ultimately is going to make the decisions about regional markets, or at last has the ultimate responsibility. Is their primary obligation to FERC? How is that exercised? Overseen?

Next, do they have an obligation to the end users to make sure that the market's functioning, to make sure that the consumers' interests are being served – to the extent to which it's under the jurisdiction or purview of the ISO? Obviously, the consumers' interests can differ from other stakeholders.

We all like to talk about the public interest, but we define it differently. How accountable is the ISO to the public interest? Does the ISO define it? Does FERC? FERC will define it in broad terms. Does the ISO board then bring it into narrower terms? How is that defined?

A board of directors has a fiduciary obligation to its corporate self-interest. At what point does the corporate self-interest, for example, in the fees that it charges, weigh against the board's other obligations? To whom are the obligations owed?

These are difficult questions. The next is: what's the function of the board, or of the organization itself? Is it the mere implementation of public or regulatory policy, or is it helping to clarify beyond the scope of how FERC has defined it?

Is it an obligation to formulate the market and to protect it, to ensure that it's competitive? I think all ISOs have some sort of market monitoring component, usually contracted out. What's the board's obligation to make sure that the market stays competitive? What about formulating the details of how the market functions beyond the guidance that's provided by FERC or, for that matter, by Congress?

ISOs will hear different points of view from stakeholders and interest groups. Is it the referee, or does it initiate things on its own, or is it some combination? To what extent can an ISO make policy? If you're in charge of the market, you control the bottleneck functions. Decisions you make have policy implications. How does that work?

The ISOs now being proposed are all not for profit, but they obviously have self-interests. How does this internal governance work? Serious process questions include how the ISO makes decisions. Does it have a consensus orientation? Should it seek all input and then make the decisions itself? What access do stakeholder and interest groups have? I'm not proposing that ISOs adopt ex parte or sunshine rules. But the same issues that face regulatory bodies to some extent are there for ISOs.

And what does the "I" in ISO stand for? From whom is it independent and for what purpose? The flip side is accountability. Is it accountable for market operations, its own corporate governance decisions? Process questions? How does it treat different stakeholders? To whom is it accountable?

Who evaluates how they perform? What do you do if you find that they're performing less than optimally or badly? Who can correct that? If they're performing well, how do you reward them?

There is the question of enforcement. In regard to a regulated utility, if FERC makes certain decisions, they essentially are enforced by the force of law that FERC has on its side, and secondly, they are enforced through rate-making mechanisms. Suppose there is a non-for-profit ISO that is out of sorts with FERC policy. Does FERC order the ISO to do something? It's difficult to think about how it could make a not-for-profit whose costs are all socialized accountable in some financial way.

Who polices the ISOs and how? What are the ISOs' liabilities? An obvious example is a race or sex discrimination complaint by an employee or prospective employee. Clearly, the ISO is liable. But who's liable if it's something related to market operations? What is the directors' standard of conduct? In a for-profit corporation it's a little easier to define than in a corporation that owes obligations to many parties.

Another issue is the relationship to FERC. An ISO can't be independent of FERC because FERC ultimately is going to make the calls for at least all the states but Texas. Is FERC just an appellate body? What is its role in the governance of the ISOs? It's laid out in Order 2000, but there are other considerations.

On the question of stakeholder involvement, I think we can all agree that that it needs to be significant. The controversy begins as soon as you start trying to define what it is. All of the ISOs have formal advisory processes that vary a little bit from region to region. What about informal input? Why should ISOs be different from any other quasi-public body and be free of lobbyists or people coming to lobby them for one particular point of view or one particular interest? What about subgroups? It's nice to have an advisory process where every interest group, at least, is represented and there's a formal process and we know that everybody who wants to be heard has the opportunity. But that's not how the world works. How do you deal with the question of smaller groups or individual interest groups and their relationship to the ISO? How do you govern it? How do you ensure that there's not some sort of unfair influence? How do you define stakeholder involvement so it is significant, meaningful and still preserves some basic notions of fairness?

One can't help but think about all the judicial rules about *ex parte* and other things. I'm not sure that's particularly appropriate in this case, but ground rules are, and that hasn't been sorted out.

There are three models for how a board is selected. One is independent and by that I mean a board of directors composed of men and women who are completely independent of any market participation status. They're not political appointments. They're chosen because of their expertise, skills and ability to ask questions and be insightful. They have no self-interest in the market.

There are two models for how these wise men and women are selected. I put "members" in quotations marks because it's defined differently in different places, but I mean that everybody that has some formal role in the ISO elects the directors, or each director. Another model is a self-renewing board. When there's a vacancy, the board picks the replacement.

There are two other models: the old California model where every stakeholder has a seat on the board and the other where the ISO is appointed as a political job, in the case of California, by the governor. As you know, there's a lot of criticism, not only because the governor appoints the board but because the state is in fact a market participant. Does this skew the decisions of the ISO to favor the state of California?

A caution is that no matter how you set the selection process, in behavioral terms, it's very easy, for example, to see how an independent board, a self-selecting board or a self-renewing board can be dominated by the stakeholder process. How hands-on should the board be, or is it simply broad oversight at a very high altitude?

What is the nature of the relationship between a board and management? One example came out of the Midwest discussions between the alliance, proposed alliance transco and MISO. An agreement was reached on slice and dice issues between management of MISO and the alliance. In the advisory process, everybody understood that the agreement was then submitted to the advisory council and then to the full body. To put it fairly, the advisors didn't like the arrangement that management had entered into. Management then shifted 180 degrees and said, "It's not a good deal and we're not going to do it." In this case, one could legitimately ask, "Do we have the California model?" We don't on paper, but in fact the stakeholders are calling the shots. Should this have been a matter where the stakeholders' input was valued but the board itself made the decision that the agreement was presented to the board?

At what point should the board have intervened? Was it obligated to do so? I have no idea what position the board may have made; it may have come to the same decision as management. Part of the reason the process didn't play out is that nobody really knew the process and who was accountable. This is critical because it's not like a for-profit where you can draw lines.

There are also some legitimate historical reasons why people need to think about the regions in somewhat specific terms. We'll set Texas apart because Texas always thinks of itself in unique terms. The northeast states, including the mid-Atlantic, have a long history of very tight power pools. While the northwest doesn't, there is a history of multi-state coordination and planning. You don't have any history of tight power pools elsewhere. The job for the ISO in getting started is phenomenally more difficult than in the Northeast. You can't underestimate it.

For example, it's nice to talk about standard market design and we should be talking about it and in some places we can actually be implementing it. But we have to recognize that in broad swathes of the country, we're really talking about a fairly lengthy transition process.

Who actually manages and makes decisions during these embryonic processes of the RTO? For a long time, I think it's fair to say that the traditional transmission operators will have a lot to say about how the market is going to function, not because the system operators are inept or incompetent, simply that they've got a long way to go to get the system up and operating, and the coordination, technology and software in place. It's a very complicated process and the politics are complicated. The institutional arrangements in the transition are not to be underestimated because when I say the RTOs will be weak in the interim, that's exactly what I'm referring to. Again, the Northeast is a huge exception because of its history of tight power pools.

Should the board be more involved early on, and then once things are up and running, it can move to a higher altitude? Again, what's the role of management and of FERC? If I were a FERC commissioner, I would be less worried about the northeast, but I'd be fairly worried about the Midwest and southeast because there are still vertically integrated transmission operators whose self-interest goes in a very different direction from the market operators or administrators who might do things from a neutral basis. How active or passive should FERC be in overseeing this process?

Again, in a transition, there are issues about stakeholder roles. In the initial stages, compare the capability of the RTO with that of the traditional transmission operator. Hopefully over time, the balance will shift so that the ROT can perform all those functions, but that's a long transition. The way MISO functioned for purposes of the putative agreement with the alliance was that, in effect, the board decided to delegate to a combination of management and the advisory council. Then the question is, to whom can the board delegate what are the ground rules? How does this relate to what management is supposed to do and how the advisory process is supposed to function?

In conclusion, there is a need to sort through these issues and a need for some direction to be given. Second, we have to acknowledge in developing these rules that the regions are not the same. They may ultimately get to the same point, but they won't be there for a considerable period.

Finally, transition matters.

Question: Would you comment on FERC's order referring to alternative dispute resolution mechanisms being built into the new RTOs?

Response: At issue is whether the ISO is a referee: is it an adjudicator of disputes, and to what extent can it delegate to an arbitration panel or other alternative dispute resolution.

Speaker Two

RTO governance interests me both personally and professionally, because I've served as a director of 17 boards and seen firsthand how important governance can be to an organization's success or failure. Until recently, corporate governance was the interest of only a few, but questions about Enron and other firms and the actions or inactions of their directors have stimulated new interest. Peter Drucker, who some consider the father of modern management, said, "Whenever an institution malfunctions as consistently as boards of directors have in nearly every major fiasco of the past 40 or 50 years, it is futile to blame men. It is the institution that malfunctions."

I believe that institutions are amoral and that it is the actions of the people in them that are either moral or immoral. I also believe that inappropriate corporate leadership, coupled with a weak or dependent board, foster cultures in which immorality is more likely to flourish. The scandals we read about reinforce the importance of vigilant and courageous directors and make clear the need for independent oversight by bodies that are separate and apart from the responsibilities and accountability of management. The failure or success of any institution, be it public or private, is reliant on an appropriate governance structure based on the entity's mission. This is especially true in the creation of RTOs because of their mission and broad scope of responsibility.

The corporate boards I served on were nominally accountable to shareholders. In reality, they were effectively self-perpetuating, with the CEO playing a major, or even a dominant role. In my experience, no director was ever removed involuntarily by shareholders, although the CEO removed several. The state boards I served on generally were accountable to the governor, according to the governor, or to the institution, according to some of the directors. Over half of the directors with whom I served were removed involuntarily by the governor, making my state board service feel like an episode of the TV series, "Survivor." Non-profit boards I served on were accountable to their institutions. I recall one director being removed, but it was the remainder of his own board. The boards of most charities, non-profit associations and private universities are usually self-perpetuating.

ISO New England's board was created in 1997, using criteria developed by a search committee comprised of market participants and state regulators. A headhunter developed a list of candidates, vetted them and submitted them for interviews by the committee, which then selected nine members, eight of whom still serve. This is similar to the structures of market boards such as stock exchanges, which consist of market participants selected by their peers. Some like the New York Stock Exchange also have independent directors.

Initially, ISO-New England's board was chosen by stakeholders; its members then gave up all financial links to the industry, and were freed from the need to lobby for reelection. Like tenured university professors or federal judges, it gives the opportunity to act apart from any special interest, including self-interest.

Now ISO-New England is working with its counterparts in other areas and with FERC to form an RTO. FERC has offered guidance on the essential features of RTOs, and of energy markets. Still unresolved is how best to govern them.

But before determining that, we should ask what an RTO's fundamental mission is, what its functions are, to whom it is accountable and the role that others play. New England has two responsibilities: run the markets and assure reliability of the network. New England also supports the creation of an independent transmission company that designs, builds, maintains, owns and finances regulated transmission.

Under this proposal, transmission planning would be done jointly. The ISO-like organization would define the needs and identify the problems. The independent transmission company would propose solutions to those problems. The ISO would then choose between regulated and merchant transmission solutions, and between generation and load response, and transmission solutions. The transmission company boards would be elected and accountable to the owners. However, there would be mechanisms to avoid conflicts if one or more of the owners is also a market participant.

FERC has stated correctly, in my judgment, that directors of the entity that runs the electric market must be independent. A truly independent RTO board is necessary to instill confidence among its stakeholders that the RTO will be operated reliably and its markets will be fair, competitive and efficient. Independence, however, is dependent on several other, equally important board characteristics. Directors should be balanced, meaning that they fairly and equitably represent the interests of the market that the RTO serves. They should be self-perpetuating. They should be accountable, since accountability is what makes delegated authority legitimate and prevents abuse.

A balanced board that is not dominated by any interest is free to consider best practices in market design and make decisions in an objective fashion. An RTO board that is dominated by one market sector or one region is impractical and counterproductive.

While I think the directors of new organizations will have to be selected by a committee of market participants and state regulators, their reelection cannot be subject to the popularity of their decisions. Sitting in judgment of decisions that affect both the buy and sell sides, frequently, RTO directors will make decisions that upset someone, or even everyone. Their appointments and service, therefore, must be free from outside influence. Self-perpetuation of directors is the only way to preserve the independence that FERC has mandated.

Experience has taught me that no governance system is without flaws. I've come to believe that the best model is a board whose directors are initially selected from input from stakeholders, independent of market participation, compensated appropriately for their independence, equally representative of all the markets they control, self-perpetuating to preserve their independence, and accountable as a public trust to FERC, rather than to any special interests.

No matter what the governing structure, board vitality is important and directors must be independent and courageous. They need character that is a combination of integrity and courage.

In deciding how RTOs should be governed, FERC has a unique opportunity to act boldly to ensure the future reliability of the nation's transmission system, and to eliminate the uncertainty overhanging future investment in transmission.

Speaker Three

We understand that there are certain laws that deal with how electricity needs to function within a system in a network. Customers need to pay for it, of course, and we need to have providers balancing their output with the load in real time. When talking about governance in this context, I suggest that we'd come to closure quickly if we were simply dealing with the physical process.

Governance is a process by which entities or individuals with different interests are organized into a team to pursue goals. Where there are issues, usually they about goals and how to reach them. Fights over governance are typically symptoms of fundamental differences in perspective.

Early efforts at restructuring go back to President Roosevelt's initiatives. His ideas were structurally oriented. He wanted to create public power entities to put some discipline into the performance of vertically integrated investor-owned utilities. It's important to retain some perspective on where we started. For example, a service territory map of Ohio shows geographically defined islands, where suppliers have been given certain rights. Cultures developed, as did measuring practices. Everybody does things a little differently, rationalizing governance or the market's performance based on the differences in perspectives about how restructuring should proceed. When you look at the number of control areas existing in most parts of the country, you begin to appreciate the significance of the tasks that an RTO has to perform effectively in order to rationalize performance of a system that knows what to do, but for human intervention.

So we begin with a history that I think is more open to RTOs and governance. For example, PJM began in 1927 and its interconnection was incorporated in 1956. Its history and experience have helped them migrate into RTO-land more conveniently than others, although not without some problems. FERC also offers perspective. Using my definition of governance, the agency defines the goals for which the governance process needs to be pursued. I think the controversy over governance can be resolved as a result of FERC helping us at a detail level.

I think everyone is frustrated with progress to date for different reasons. Ohio is finally at a point where a majority of the Public Utilities Commission is trying to make markets work, being sensitive to the politics associated with these issues and the substantive matters that haven't yet been resolved. Three RTOs are vying for turf. And the Enron incident is complicating everybody's ideas about what needs to happen. With Arthur

Andersen struggling as one of the participants, there are questions about the flow of information -- the lifeblood of any organization -- that is dominated by accounting rules. If you cannot lean on the accounting information that sits under the organization as a basis for making business decisions, you're in trouble.

There have been some questions about independence governance regarding the Alliance companies. There are different views about the role of regulators or state governors and their responsibility for managing the grid. We've also discussed to what extent stakeholders on an island will have the opportunity to affect outcomes, or when they might be rescued from themselves, perhaps.

Fiduciary duties are an interesting subject. If you spend time in trust, property or malpractice law, you find that they're very flexible in their making. Typically, they involve duties of loyalty and care that are variable, depending upon the circumstance. I mention this because it's too convenient to use the term fiduciary duty and expect that somebody necessarily will understand what it means.

Fiduciary duties really are different. Given an RTO's range of responsibilities, it's reasonable to expect that the duty of loyalty and the duty of care may be different, depending upon the subject matter. For example, the duty of the RTO board with regard to protecting the property of transmission owners is a subject that really is more common in the context of legal documents and legal discussions. As in a landlord/tenant situation, a tenant cannot commit waste of the apartment, or destroy things without being subject to penalties.

I think it's easier to visualize or think about the common experiences of people, but I suggest that the duties of loyalty and care need to be examined by function within the RTO, whether it's reliability, taking care of property, collecting revenues or paying transmission owners. By thinking about it in these terms, you may see that fiduciary duties are variable, at least based upon history and legal principles.

General corporate theory is useful. From my experience, most of the directors that come to RTO boards bring some prior corporate board experience and have expectations based upon their experiences, about what their roles and responsibilities may be. Originally, corporations were owned by managers and managed by the owners; there really wasn't much confusion about governance. Today we have professional managers that are distant from customers and employees at times. We have very different circumstances, limitations on liability and so forth.

But if you weed through the corporate theory, you often find people advocating in favor of placing control over the corporation in those individuals or entities that have the most at risk based on performance. I think that most of the at-risk constituents right now consist of transmission-dependent customers, retail customers in open-access sates and independent merchant power producers. General corporate theory would suggest that putting control more in those populations might help to better align the performance of the organization with the public interest, whatever that may be. Being at risk for performance is a healthy and real-time motivator.

The stakeholders' role I think is to provide guidance. The backstop provider of the public interest in almost every case is either FERC or state commissions. When we don't like what the RTO board is doing, stakeholders have an obligation to let FERC know their views, or that they weren't sought out, in some cases, by the process inside the RTO. FERC has a responsibility to protect the process, as well as to fundamentally resolve the differences in where the public interest lies.

What you see now is a number of layers where watchdogs have been set up to help FERC identify early where problems are occurring. The RTO, stakeholders, market participants all have rights to participate in FERC proceedings; you have an emerging role, perhaps motivated for political reasons for a meaningful role for state commissions. In standard market design, although it's somewhat ambiguous, you see FERC continuing to try to mend some fences by letting state commissions know that they are going to have a specific and meaningful role in what FERC does on a going-forward basis.

What are the incentives for directors to guide the RTO? I researched the approach at MISO as it set director compensation. From the survey that was done in that context, it appears that there was not much done in for-profit or not-for-profit corporations to incent directors to perform in a certain way. For-profits typically have some opportunity for share participation that may be an indirect mechanism for incenting behavior. Stakeholders have suggested keeping the fundamental goals of the RTO documented in a way so that they would be before the directors continuously as a check against performance. Incentives in the Midwest ISO structure for managers are driven by rather crude RTO functions that haven't been fulfilled yet, but steps are being taken at the upper management level to recognize gain what the organization's goals are. Again, from my perspective, if we can agree on the goals, the governance issues will quickly slip by the side.

Speaker Four

We need to begin all of our proceedings each day, each month and each year with the end in mind. That end was put forth in 1992 with the revisions of the Energy Policy Act. The revisions brought the exempt wholesale generator and the power marketer under the governance of the Federal Power Act. With that introduction, the law said that no longer did generation necessarily need to be brought forth in vertically integrated forms, and that competition at the wholesale electric energy level was achievable. Technology has improved and the markets could go forward.

As we look at rule makings and market proceedings, we have to take into account where they began and remember that our goal is to create consumer value through the introduction of competitive wholesale energy markets. Each state and region will reach that goal in a different manner, but the goal is consistent.

The three Northeast pools have a rich history of integrated operations. California did not operate as a tight pool at its beginning, but it only had three investor-owned utilities, and it didn't have the myriad of smaller entities like the Midwest. The characteristic that distinguished PJM from New England, New York and California is the process by which they took their initial steps of achieving competitive wholesale electrical markets. They didn't all divest of generation within a very short period of time. PSM came forward, and others, driven by possibly different state commissions, did different things. That's what markets are about – choice.

In New York, New England and California, the generator owners got on one side and the transmission owners on the other. When you have distinct, competing interests like that it's hard to bring markets together. When you look at governance successes or the other elements that add to the success of a market, it's easier to achieve market success in markets where participants are more amorphous.

With RTOs there are some fundamentals, such as no matter how hard it is to start, get it right as early as you can. You will come from some transition: ISOs will transition to RTOs, and an integrated structure as seen in the Midwest that really never took that ISO step perhaps, will transition to RTOs.

Ultimately, both the board and management's mission is to rely upon competitive markets to ensure reliability and to keep electric prices reasonable and to bring consumer value in competitive electric markets forward. I argue that when you focus on minimizing prices short-term, consumer good is not created in the long term.

How do you constitute a board? Candidates should come through an independent search firm. They need to meet a professional or technical standard and especially in the early days, have to be willing to serve and appear in a virtual or near full-time capacity. This is important because their attention needs to be on their roles early. One needs to pay attention to compensation because of the conflict of interest standard and that many people have livelihoods that have evolved.

Members need a variety of backgrounds, for example, in information technology; financial and commodity markets and the energy industry.

I suggest that members serve staggered terms of limited duration and that no board member should be term-limited. Elections are fairly straightforward: an independent search firm selects candidates who are elected by stakeholders. The election is a super majority so that it doesn't become a popularity contest, but depending on how you do sectors, there are only a few where the math really matters, and it's not in market operations.

I believe that a board member can sit on more than one RTO board, absent seams issues. The board is the ultimate final decision-maker, absent FERC. Members should have oversight over hiring RTO senior management and budget approval with stakeholder input, and setting and measuring the progress of RTO staff toward goals. I think the board, RTO and all market participants share responsibility for operating the system in accordance with established reliability standards and that FERC oversees market operations.

In my opinion, states bear the larger responsibility in achieving the goal of moving to competitive wholesale markets. States must enact policy and implementation to help carry that out. There is no "one size fits all" when it comes to default service, provider of last resort or retail access. The latter dos not necessarily create the value of wholesale competition. You must have one before you move on to the other. I believe that retail is really a large billing systems issue.

The stakeholder advisory committee is representative of the market sectors. I don't have any firm belief of how many members there should be. They should participate through working committee with staff support, and staff can provide input about potential impacts and costs that various proposals will create. State regulatory bodies must be participants to ensure that the foundation upon which the markets are performing will allow them to enact competitive wholesale markets in their states.

How do people vote and how does the board make decisions? When considering proposals, the board should be shown the votes of each sector. Don't aggregate across sectors on maters of market design or market authority because the math doesn't work out.

Finally, the role of the staff is to support and facilitate, but staff issues and concerns should be vetted out via the stakeholder process.

An independent market monitoring unit with a separate board that's incorporated into the RTO tariff for FERC approval is another part of the foundation for designing good mechanics. It is not a substitute for structuring RTO market rules or the establishment of truly independent governance. In California the independent market monitoring unit has sometimes received a bad rap because it is looked upon to fix the governance problem, which in reality has to be fixed by the stakeholders and ultimately through FERC intervention. The unit needs to be charged with monitoring and auditing functions on a regular basis to ensure stakeholder participation and compliance with tariffs.

Whether you agree or disagree, it is important to keep an eye on where we're trying to go. As market participants, let us never forget that our goal is to ensure that consumers have access to competitive wholesale electric markets.

Question: The speakers started from the assumption that governance in some form can work and can fix the full scope of the problems that might be presented to an ISO or RTO and the full board. I think that when things are right in a market design, governance in a lot of different forms works. We can fine-tune it and there are reasonable people to make small, equitable tradeoffs among the participants. When the market design is wrong, there are huge potentials for transfer among participants. Depending on your view, they're good or bad, but the money is huge and it's from one pocket to another. It's close to a zero sum game. Governance is then supervising a bunch of small kids trying to divvy up a stack of money and to me that is inherently infeasible. If you can get an RTO design or process in some form and superimpose governance on top and make it work, is that the way to go, or do you have to have a working market design and then slip it into these structures to see what happens?

Response: If the market is functioning, governance issues are secondary, that's true. But someone had to decide how the markets were made and make the adjustments. What you may regard as functional, someone else may regard as completely dysfunctional, and there are always going to be those kinds of disputes and somebody's got to call the shots. Your basic principle is get the markets right and who could argue with that?

Response: If you have poor governance, your ability to move progressively and achieve consumer good is really stalemated. But with good governance and good state regulatory participation, working toward getting good default service done or whatever you call it in your state, we will achieve a lot of consumer value.

Question: Does this suggest that there is a minimum threshold of design coming out of the standard market design process, and a reasonable minimum level of specificity in certain areas, that FERC should insist upon, prior to allowing the governance process to commence, as opposed to allowing the governance process to finish off too much of the design?

Response: Intellectually many of us might agree that the decision about the scope and configuration of an RTO ought to be driven strictly by the grid's physical realities. If we'd all agree, we could say that there must be three in North America. When you recall the heat that FERC took when it said four or five, one appreciates the role of political intrigue in trying to fulfill what we might agree as appropriate intellectually. We try to manage the political risk by moving transitionally and I think that California demonstrates that once the political engine engages, nothing good happens from there. Now some

FERC commissioners are trying to manage tensions, politics, state, federal, jurisdictional constituent groups, but at the same time move quickly to break down some of the barriers that will allow the physical system to resemble more clearly what is needed to allow the market to work.

Governance is the ability of political risk to be managed so that the outcomes that are physically appropriate can occur. It helps the constituents feel like they have a place to go. If the RTO displays credibility and integrity, it helps to manage the turmoil that potentially can exist if it's not there.

Comment: Standard market design in some cases may be a practical achievement, while in others it's purely aspirational at this stage. Getting market design right, getting governance right is not one or the other. You've got to get both right because transition matters. And in large parts of this country, we're nowhere near FERC's standard market design proposal. Governance inevitably has to play a key role in figuring out how we get there.

Comment: New England started with a flawed market and flawed governance. If we could fix the governance, we probably could move faster in fixing the market than we could with flawed governance. It's hard to fix under a governance structure that requires this crowd to agree to give up money.

Comment: The only consistent definition of accountability has to be that in some fashion they have to be accountable to FERC because they carry out a public interest charge that has to be defined by FERC. If you go to any other set of relationships you simply have conflicts in terms of responsibilities and you don't have any principle by which the board can truly orient itself. FERC itself is a political body. We may say, "Let's keep politics out of these governance boards," yet at the same time we do have a political responsibility. How do you correct a board that gets off the trace, for example, a self-perpetuating board where no one has the power to replace or change? Unless FERC controls the membership, what's the solution?

Comment: We should be accountable to FERC. Our job is to run fair, efficient, competitive markets and ensure reliability and that's the end of our public interest. We don't get into judgments on where transmission lines should be built.

Comment: FERC is not equipped today, legally, structurally or philosophically to accept its side of accountability. It created the RTO and it can dissolve it. The solution is to fix FERC, not to make us accountable to someone else.

Comment: The qualification I would add to the list for board members is political sophistication, in the sense of understanding the dynamics, the parties and how to formulate and defend decisions in ways that are politically acceptable. You shouldn't be driven by politics, though. An argument for transcos as RTOs was that if they're for-profit transcos, we know how to hold them accountable. If this commission appears to have ruled that out, even if FERC were equipped to deal with accountability, how does it do that? It could remove directors or collapse organizations, but that's not the first resort. Who holds FERC accountable? It's not the best idea to have a self-renewing board because you don't want people picking the others with whom they're going to work. On the other hand, I'm disturbed by assertions that we need a super majority. That gives certain interests or coalitions effective vetoes. It's difficult to see how individually or collectively one holds the ISO or its board members accountable, and if these are going to be not-for-profit entities, we've made it more difficult.

Response: Self-perpetuating boards are like free market economics in this country: full of flaws, but better than the alternatives. There are degrees of self-perpetuating boards. If you were selected initially by a committee of market participants and regulators, you can't start with a self-perpetuating board. I'm an advocate of age limits and perhaps term limits, although they would be relatively long. When you need a new director, you go through the same process and have the participants and state regulators help select the replacement. I get hung up on reelections. If you've got a three-year term, you've got to go to participants to get reelected. I think that will change the whole chemistry of the board and it's the piece I find most bothersome.

Response: What you see now is a reflection of what we do from a national perspective on governance. You have a series of checks and balances embedded. You have disinterested board members independent from market participants. The market monitor has lines of information flowing to state and federal regulators. Stakeholders have responsibilities inside the organization and the opportunity to petition FERC if they don't like the way things are going. These influences all have the potential to operate as a check on the organization. Congress delegates authority to FERC; FERC delegates authority to RTOs. Before we're done, we're going to see some legal questions about the extent to which FERC can delegate responsibility to a for-profit or a not-for-profit entity. Once you get out of the context of FERC acting in a remediation mode to address what it finds as an anti-competitive structure in the industry, its flexibility to interpose an RTO is much narrower. I would more broadly cast the responsibility of an RTO board. It is not just reliability and functions. It is designed to separate ownership and control so the market has a chance of existing. Once you get beyond that, FERC has a difficult time delegating pricing authority or reliability authority or anything else to an organization.

Question: An RTO's fundamental mission is to run an efficient market and ensure network reliability. I think that's the right formulation. But I see a strong tendency to lean much more in the direction that one of the ISO's or RTO's responsibilities is to make sure prices don't go up, especially in the short run. If generators are told to run, but they're not going to be included in the pricing algorithm because it would make prices high, so we're going to run them and pay them off on the side, that's a discriminatory kind of purchasing mechanism that is the classic procedure for monopsony. The market is not going to function if that's what FERC wants ISOs to do. Does local politics push FERC or do you stand up for principle?

Response: Running a unit that's not setting the market-clearing price is wrong and produces bad results. Maybe the market rules say you have to do this because the unit was operating at its low operating limit that was set ridiculously by the bid. The solution is to fix the market with new rules. A smoothly functioning market with a set of rules that makes sense means the results are what they are. You don't have control of the market one way or the other.

Response: Operating through RTOs and other arms, FERC is there to ensure a foundation for competitive energy market rules. For consumers to enjoy the benefits, states must step in because they act on behalf of their consumers. California did not have a good setup and had poor market rules and poor governance. You're always going to have hiccups, but you can fix them with good governance and good starting market rules.

Comment: There are two channels for the purposes of pricing energy: traditional regulation and market pricing authority. To the extend that you see dysfunction in a market, you're more likely to see FERC retreating to traditional regulation for purposes of establishing prices, regardless of what we might think about the efficiency of that. It is necessary from a public interest perspective at least, to keep everybody civil. In transition, there are probably going to be caps on the ability of prices. Ohio pays extraordinary amounts as stranded or uneconomic cost payments to suppliers, underwriting transitionally the revenue requirement of the transmission providers. In context the notion is that there may be some need to impose discipline on the volatility of prices form a customer's perspective, transitionally.

Comment: Transmission is the stuff that joins supply and demand. It will continue to be regulated. The transmission owner is also at risk, maybe ultimately, for failures of the transmission system. Given those, if we entrust planning and investment decisions for transmission in a market participant process, which might amount to a voting process in some areas, what are the implications for stability of the system and accountability for its functions? Do we run a risk that the system will morph from regulated and well engineered to something with fixes that are Scotch-taped on?

Response: You shouldn't accept that all transmission is a regulated public utility. FERC supports merchant transmission. Where transmission is proposed as a solution, the RTO board would decide between merchant and regulated companies. Transmission problems can also be solved with generation or load response and the RTO should make that choice.

Response: FERC has said that market participants cannot be the decision-makers for an RTO. We are constrained, probably appropriately, to having an independent organization. To the extent that FERC was delegating responsibility to market participants, it sounds a lot like deregulated monopolies and is more open to criticism from legal and public interest perspectives.

Response: No matter how we design the market, I don't know that we are really confident that the market signals are always going to get it right. There will always be some need for a fallback position. If the current transmission owners are the regulatory fallback, they're obviously interested financially at least, in their role as market participants. In and of itself that is a little troubling. But you have to add something else, if what's called for requires siting approval by the state or multiple states. It's very easy for a vertically integrated entity that sees its interest as more of a market participant than a transmission owner to just stumble its way into institutional problems in getting new lines sited. How do you make the regulatory fallback align with the different interests of the marketplace? Where there is no long history of power pooling, the ability of the incumbent transmission owners to manipulate the market is almost endless. Someday it won't be, but it's clearly the case for the foreseeable future.

Question: The "o" stands for operator and not regulator. When we talk about delegation of regulatory authority, isn't it really authorization of operational authority? You're authorized to operate in a certain way, rather than delegate it to any regulatory function. This is important because when you get into the market monitoring activity, should the monitor be a reporter of actions or some sort of enforcer? Another issue is that when you're obligated to take over someone else's property, there is a host of contractual obligations that you enter into when you create the RTO. Those issue provide one set of boundaries; politics provides another set and FERC is another. In trying to create an RTO in the northwest, the politics of public versus investor-owned companies, of state control of Bonneville Power Administration are live political discussions that have real bearing where traditionally there has been a substantial political viewpoint differential. To me, a self-perpetuating board is an aristocracy. If it starts to divert to the right, we've got no way to jerk it back.

Comment: I don't think we're out there to set a reasonable price, but rather to have a fair, competitive market. But there are issues that arise that have a regulatory aura to them, and I don't see how you get rid of that.

Comment: You cannot have FERC delegating responsibility over the range of subjects it has identified, without having some regulatory authority at least in the short run, with the RTO being a decision-maker by default on matters that have market significance. The practical reality is that if you look at RTOs as a remedial device, they need to be both operator and regulator in order to fulfill that responsibility.

Comment: The problem is that no matter how well FERC functions or how well you think it functions, it's not going to be sufficiently sensitive to different regional considerations. If all the issues with regulatory components come to FERC rather than being resolved either at the ISO level or at the arbitration panel, or wherever, I think you'll end up with something that's equally dysfunctional. No matter how prescriptive they want to be, FERC is going to have to delegate, or al least accept that the ISO is going to make decisions that have strong regulatory components.

Question: I believe that it's imperative that optional retail demand response has a seat in the creation of efficient markets. How powerful a role can it play?

Response: New England is moving into a period where we're going to have more than adequate generation, so that we've got a supply curve that is in a range where demand response works. But when there are days where we're short, you're looking at a vertical supply curve and then the market no longer works. The only way to get shape into it under those circumstances is to have load response. Inadequate supply is not solvable with time of day metering because the market price is not perfectly correlated with time of day. We're pushing an Internet-based system where the real price is actually received by the customer.

Response: A lot of it is tied to the structure of retail markets and if end users receive price signals. One thing California has taught us is that it's not good for a competitive market when consumers don't see the prices. In the states that have restructured, the results are less than thrilling. Recent statistics from Pennsylvania indicate that the amount of customers switching is negligible except in Philadelphia, where the bulk of them are tied to some affiliate of Philadelphia Electric. Without having competitive retail markets, I don't know what the answer is. Some industrials are seeing the signals and are reacting. Is that sufficient? I don't think so.

Response: The end-use consumer participation is another form of supply, just the reverse of a demand. When you look at it form the FERC or the RTO market design, it needs to be accommodated and there are some technological barriers that need to be overcome, especially depending on a smaller-sized customer. At the federal and interstate levels, RTOs and FERC need to accommodate so that their rules allow essentially a load to look like a supply at times. States also have a large burden in this effort.

Comment: When you don't have a competitive wholesale market, then the state regulator sets a price to beat, whatever you call it in your state. That's just a different form of regulation.

Response: There may be states where there is not much value in retail, such as New Mexico, because there aren't enough people. But those consumers can enjoy a lot of the benefit we are creating in having good, competitive wholesale energy markets.

Comment: I believe PJM just filed to make its emergency program permanent and add an economic component. The Midwest ISO is insisting on customers being able to bid as part of the congestion management strategy. There are many retail-oriented programs that aren't called demand response, but really are. Interruptible customers in Ohio, for example, can buy through interruptions and go directly to the market even in a regulatory context. There are similar programs in Indiana that is still a closed state. I suggest that the ultimate demand response program has been in effect forever: if there's not enough supply, customers get curtained and the network begins to isolate load. The challenge is to introduce performance-oriented demand response programs, to take them out of the structure that now is a demand response within a control area, and allow that to be exhibited more profoundly in an appropriate scope and configuration so that it can have a beneficial impact in helping to build liquidity in the secondary market.

Comment: Curtailments are not necessarily the ultimate demand response, but the failure of a system. A more efficient system would operate on economics, as opposed to an arbitrary switch in someone's hands.

Response: Part of this is cultural. The response to protect the network, assets and property is that you begin to isolate customers. That is the mechanism presently in place, the one that came with the current program. The same situation existed on the gas side of the business for years, until we introduced operational flow orders, operational matching orders. The market began to display virtual parking, real parking – the different products and services that can help to introduce what I'd call market-based mechanisms to deal with differences between load and supply. Right now, customers are basically carrying the risk of a dysfunctional physical supply condition and they are providers of last resort of reliability.

Comment: I've heard people say that the average residential customer can't respond to prices. My assistant, who has two teen-aged daughters, calculated that at the prices that were being charged in California, she could shut down her two heat pumps on a hot summer in Virginia, take her daughters to the movies and buy popcorn and still save twenty-five dollars.

Question: FERC seems to believe that there is a place for alternative dispute resolution mechanisms in future RTOs. Is FERC right about the continued use of ADR in the new structures?

Response: There's a need for ADR if the participants can't solve the problem themselves. The easiest example is when you have a cost that you're going to socialize, you develop a formula to establish how much goes to each participant. The total amount is known, but not how it gets distributed.

Response: Separate the disputes into two categories. ADR lends itself reasonably well to simple commercial disputes. But if you have a dispute with all sorts of policy questions, I'm less than sanguine about ADR as a mechanism. Regulatory commissions often see all parties look around the room to see who's not there and then say, let's screw him and this happens more times than not. As an ISO board member, this is problematic because

I know who's getting screwed. Do I tolerate it because it's the course of least resistance or do I stick my neck out and do something?

Response: As a practical matter, a market participant can take it to FERC ultimately. Resolving things through ADR is a lot less docket clogging at FERC.

Question: The governance model being developed in SeTrans is one where you simply hire a for-profit company to operate the system as the RTO. It brings its own board with fiduciary responsibility to its stockholders. It is not and cannot be a market participant. Is this a good model?

Response: It's a way to structure an organization to be responsive to FERC's objectives. The governance that sits underneath the organization still has to be aligned.

Response: If it's not asset-based, if the manager is not the transmission owner, I think you have some of the same difficulties you have with an ISO. The fact that it's for-profit or not, if it's not asset-based I'm not sure changes things that much.

Response: A for-profit company could be a fine implementer if the goals and the rules that it's implementing on behalf of those parties that are ultimately charged either at the state or federal level with producing a good competitive market are well defined.

Response: You'd end up having an operator contracting with the RTO, acting as agent, and a sub-delegee of responsibility that has initially been delegated by Congress to FERC, from FERC to RTO, now from RTO to contract operator.

Comment: Let me clarify that the model is a contract operator that is the RTO, and that does not own assets.

Question: Each speaker at some point has referred to balance on the board. It just seems to drop on the table as an assumption that boards have to have balance. I submit that it really is irrelevant. We've had RTO boards that are designed entirely by the transmission owners, as with PJM. We've got pre-RTO regulation that was done entirely from the consumer point of view and I think most people liked what they got in that regime, although one of the reasons we're dealing with restructuring today is because of that approach. An RTO governed entirely by sellers would work perfectly well. You can't have a market that doesn't have both buyers and sellers. If sellers were to run the entire marketplace, wouldn't you end up with the same structure? If balance only means having a certain set of skill sets on the board, that's fine. Isn't what people mean by balance a dynamic tension built into the board structurally in the stalemate sense? If not, what's to prevent it, particularly with a self-perpetuating board?

Response: There's certainly an argument for professional diversity. The California ISO was well balanced. As you pointed out, it was a prescription for stalemate. The notion is that the members must be independent, capable of making their own decisions and are sophisticated politically. Certainly they ought to understand the views and perspective of each market participant, but not represent them. That is not their obligation. You want balance only in the sense that you have new people who truly have no particular interest one way or the other, but not balance in the sense that every interest is represented.

Response: Because my background is in the physical side of the business, what is always scary is walking into a whole room of lawyers trying to define a system. Likewise, a room full of people just like me would worry me because we'll be so hung up on the proper load flow equations and argue and won't create any value.

Response: We've got one person with regulatory experience; an economist; two with utility experience – and you have to be sure there's no involvement in any market participant; two with market and two with finance. There are no lawyers.

Comment: A mediator is often good.

Question: The market monitoring functions are within the RTO governance in the three northeast RTOs. Professional staff reports to the CEO and is overseen by the respective boards. In the process of merging New England and New York, this is a topic of debate. Some feel strongly that the monitoring function should be completely outside RTO governance, accountable directly to FERC. Some believe it should remain within and be under the RTO governance process. Some say it should be a hybrid where staff could be within the RTO, but there would be an outside policy board that would set policy and direction and perhaps resolve disputes associated with market monitoring issues. What do you think?

Response: If we accept that there should be market monitoring, where is it housed, who does it report to and what authority does it have? The trend suggests that there will be redundant reporting. The information coming from the monitor would be available at least to FERC and state regulators, maybe others, so that there is somebody in a position to do something with the information. More interesting is the question of the monitor's authority and the extent to which its authority can be delegated to multiple entities underneath the governance. My view is that you'll end up with the market monitor making information available and somebody else decides what to do with the information and when to intervene. Those issues are going to be resolved on political terms. Where we are in much of this is that we trust the market but not its individual participants.

Response: You need an independent market monitor. You need an independent auditor. There has to be staff on the job, hands-on all the time and they report to somebody within the organization. They also need to report to the monitor and say, "Here's something you need to look into," or, "What should we be doing about this?" There is also the operational audit function: are the operators obeying the RTO rules and running the market they way they are supposed to? KPMG, for example, might do the operational audit which says is the RTO compliant with the rules? The market monitor with assistant from on-site staff asks if the market is performing as it should, if is there market power, or should the rules be changed.

Comment: The monitor's function is like the federal Securities and Exchange Commission's job: to make the market more transparent, report on what is going on. Who it reports to is secondary because basically, it reports to everybody. FERC, the RTO, individual market participants may use the monitor's information. There are all sorts of ways one could enforce misbehavior, if you will.

Question: On liability, ultimately the customers are at great risk, but so are the transmission and distribution service providers, as planning and operations functions change. Some RTOs or other transmission organizations want liability protection. Possibly it's the issue of simple versus gross negligence. How do you harmonize the liability issue with the question of accountability? If you're not liable financially or in any other matter, how are you really accountable?

Response: It's more than reliability related to property damage or injury. More visible recently as a result of Enron's failure is how you deal with the trapped costs associated with someone not performing on a contract. In many instances, existing transmission owners have exculpatory language in their tariffs. To the extent that an RTO's exculpatory language in its tariff is similar, I'm not sure that is much of a change. If the allocation of risk is explicit, people will have an opportunity to contract or protect against the risk that is assigned to them. It's important at least, to understand where the risks are and I think it's ambiguous right now.

Response: There is a substantial legal question about the enforceability of those clauses, whereas, when you look at a not-for-profit, non-asset-based ISO, there's no question. The liability is socialized. There's no place else to put it unless the board assumes it personally.

Comment: The other option is you're not liable and it's not socialized. The party that's harmed is harmed.

Response: You're right, but neither option is designed to induce accountability.

Session Two. Beyond a Standard Market Design

The debate about standard market design should be drawing to a close. A standard market design provides a default mechanism needed to move forward with RTOs. The core components of a bid-based, security-constrained, economic dispatch with locational prices and financial transmission rights are well understood. Moving beyond the basics, further development will be needed to address regional choices for important remaining issues; to what extent should there be socialization of costs for connections, expansion or operations? What forms of hybrid models with alternative financial transmission rights will succeed in the market? How will existing transmission rights and contracts be treated in regions like the West where the standard design is a major departure from recent practice? How can regulators and market participants best deal with revising market designs to correct problems in early implementations? The old seams issues are reduced but not eliminated through adoption of a standard market design; how will these be handled? How can the cost and delay in getting the basics accepted be avoided or compressed as we get into the next level of detail? What needs to be done beyond the standard market design?

Speaker One:

There has been a long conversation about the nature of transmission rights. It started with the contract path picture, which if the world were that simple, would have worked fine. Then there were years of discussion about various link-based methods, or looking at the parallel flows and trying to get rights on every link in the system. People would trade physical rights and that's how you would manage the use of the transmission grid. The idea died because of the impracticalities. Next came point-to-point rights, interpreted for example, in the capacity reservation tariff as point-to-point physical rights. Again, it suffers from the deficiencies mentioned in the physical rights. Now it's become implemented as point-to-point financial rights. Lately, the flowgate story has been resurrected to mean not physical but financial flow gates that will be integrated into a system and treated as financial rights. Wouldn't it be nice if we could have everything? That's the characterization of the hybrid.

A few people, including myself, think things are a little more complicated than we appreciate. I think the challenge can be found in two papers: the standard market design white paper produced by FERC and MISO's proposal for congestion management. What do you need to do, what do you have to know and what are the questions to ask about technical feasibility?

My conclusion is that we don't know. It's an empirical question when you lay out what needs to be done. You'd have to do tests. My guess is that we should be worried that it's not at all obvious that it's technically feasible.

If you think about flow gate rights as physical rights, the notion is that there were just a few flow gates that were the constraints. We knew about their capacity limits, DC load shift factors and power transfer factors, and the transactions over the flow gates. If these things were all true, we could just award the rights to use particular flow gates and people could trade them in a secondary market and that would decide how the system operated.

There were more problems than we expected. We didn't know what the capacity was and the power transfer factors and the shift factors were changing all the time. It took about a year and a half for people to become convinced that it was a more complicated situation. The idea of having physical flow gates that would actually match what peopled did and control the system went away and that's a good thing.

Now we're into the financial story that centers on the standard market design idea that was also in the RTO. You have the coordinated spot market, bid-based security-constrained, economic dispatch with nodal prices and you charge for bilateral schedules at the difference in the nodal prices. Then you can have financial transmission rights.

Point-to-point is exactly that. You identify a source and a destination, or input and output locations. There's nothing special about having just two; you could have more complicated versions. The right is that you get to collect the difference in the locational prices at the source and the destination. Obviously, if you're transmitting power from the source to the destination, you're charged the difference, and if you have the FTR and you're paid this difference, the net cost is zero after you get the FTR. This is the point-to-point obligation.

It's very important that you get paid this amount. Sometimes it can be negative and you are paid to provide counter flow. In the right, you pay back the money, it still zeros out, it's still the perfect hedge and everything matches.

This system has been implemented in PJM for congestion in a framework that uses a DC load approximation, and in New York in a different approximation that uses the AC system. The problem is that people don't like the negative payment part. An alternative is to find an option where you are paid if the payment is positive, and if it's zero, you aren't. It's like having the right to schedule -or not -a physical right. There's no obligation. There's a very close connection between the physical and the financial interpretations.

While there is nothing wrong with this idea in principle, it's more complicated to evaluate simultaneous feasibility so that you don't give away more options than the system can support. This technical problem is being investigated.

The flow gate idea differs in that there's a shadow price that comes out of the economic dispatch that's associated with every constraint in the system. You can buy a right, known as the flow gate forward contract, to use a particular constraint. You are paid the shadow prices times the amount of the right that you've paid. Much like the point-to-point option, the obligation can be positive or negative. You can provide counter flow in the obligation definition, or in the option definition you can restrict it only to directions that are positive – only things that are in the same direction as the constraint.

If this is feasible and not too complicated, the market will use it. I predict that it is too complicated, but I could be wrong.

In the actual system, you have to worry about contingency constraints. For example if the line from 1 to 2 goes down, there is another set of flows and another set of constraints that define another set of flow gates. Then you would have to worry if line 2 to 3 goes down, or 2 to 4, and that's another set, and so on.

Adding all the security constraints doesn't make any difference for point-to-point obligations because it's still just the difference in the price at the two locations. That's an important simplification that is going to matter.

How do you demonstrate technical feasibility? Physically, you don't want to give away more than the available transmission capacity. The financial counterpart is that you want enough money to pay for the FTRs; in other words, revenue adequacy.

The answer is simultaneous feasibility. It's slightly modified, depending on how losses are treated and whether you've got an AC or DC model. Simultaneous feasibility means that if you actually dispatch a system according to the rights, it in fact would be feasible.

In an actual dispatch, there probably won't be hundreds of thousands of other constraints; potentially though, there could be. This is relevant in terms of what you have to think about. The solutions are bid-based security constraint and economic dispatch. You meter constantly what the grid does so that you know the flows within a few minutes ago. That is the starting point to figure out how much you're going to adjust the solution. The computations use a procedure called relaxation, meaning ignore all the constraints and check to see if you would violate any. If you are, impose them in the optimization and then resolve it. You go through this process a couple of times and you linearize it.

The method works because you start close to the solution. You have the supercomputer of the real analog system working efficiently for you and you can do the relaxation scheme, and not many constraints are binding. A critical part of the hybrid models is being able to conduct an auction where you sell the FTRs and a well-designed hybrid means solving the auction model efficiently, quickly and correctly

The auction structure for point-to-point obligations is almost identical to the formulation for the dispatch. In the real system, the real schedules are actually obligations because they produce counter flow. The solution procedure for the actual dispatch can be applied to the auction model, but it's a little harder because you can't actually measure what's happening six months from now. You have to do some computations.

Options are more complicated. I have discussed these interactions with some software vendors. The idea is that you look at all possible combinations of the exercise of the options, so for example, if I don't use my schedule, then I'm not providing counter flow for you, so you can't schedule yours. You define a worstcase analysis that confines the constraints. Preliminary tests suggest that it's doable in the DC case and a little more problematic in the AC case. In the flow gate story, the idea is that you are essentially selling the capacity of every one of these hundreds of thousands of constraints and people can buy various combinations as they wish in order to capture the economic benefit associated with using the constraints. The mathematical formulation is quite simple until you think about the computational implication and that is a potentially serious issue.

Of course, flow gates don't exist in the actual dispatch in the sense you can't buy a right on the flow gate in the actual dispatch. There is no separate sale of the flow gate. It's a different kind of formulation, and not the same as the dispatch model. In the auction, when you're looking ahead, any flow gate that might be constraining should elicit a positive price. This is an arbitrage condition. You monitor the things that might be constraining. Logic says that when you're looking ahead, in principle anything could be constraining and could elicit a positive price in the auction. Potentially, and probably likely if there are no restrictions on it, every one of several hundred thousand potential constraints in the auction might be binding.

That precludes using the software implementations that have been used to solve the dispatch model, or the auctions in PJM, because you can't use the relaxation strategy. Remember that strategy is based on the assumption that only a few constraints are binding. It won't work if everything is binding. I don't know the answer to this problem. Solutions that aren't so appealing include not having so many flow gates. But then we're back to commercially significant slow flow gates and we're going to either ignore the cost of the others or socialize the cost of the rest. Another unappealing solution is that instead of an auction, we'll distribute the flow gates and let the market figure out how to solve the problem. However, you have to be able to run continuous auctions so that you can reconfigure how you use the system until the time when you switch over to an obligation framework, which is to get up to the actual dispatch. You can't dispense with the auctions or you're back into the same problem of trading physical rights because you can't get the rights to match what you're doing in reconfiguring.

Solving problems in the context of options means figuring out how to adapt the software. But we have to recognize that our adaptive mechanism doesn't work for flow gates because of the nature of the bids, which will turn out to be different than they are with point-to-point obligations and options. This is a challenge to the hybrid model idea. There have been claims that the hybrid models are equivalent, and I agree they are at a mathematical level, but they're not equivalent in terms of their operational implications for real systems.

Maybe the answer is to distribute a few commercially significant ones arbitrarily, but not others, don't socialize it, and live with that, whatever you do with the flow gates. Somebody's going to have to decide how to simplify this problem or invent an alternative algorithm. What is clear is that FERC's staff paper on standard market design and the MISO order both say that we can start with point-to-point FTR obligations and it's also clear that market participants want options. However, I'm much less confident that we can deal with flow gates and all the other things at the same time. But maybe if we could get the option mechanism to work, it wouldn't be necessary.

Question: Part of what we're seeing is what I call a superiority of the product in that an FTR right or option essentially allows the preferences of the parties to establish the values for what is constraining on the physical system, whereas the flow gate starts with an *ex-ante* assumption, and forces you to look at everything in terms of enumerating the solution. Is the corollary that I don't need to now anything other than my preferences for hedging or financial protection with the FTR, but with the flow gate right, I have to make many assumptions about what it is that I'm trying to protect?

Speaker Two

The Texas model is interesting because a lot of ideas that I think you're seeing on the federal level were first thought about and implemented in Texas. We were the first ISO in the country. We started in May 99 with legislation that enabled wholesale competition. We made the wholesale market work before we got to retail. The pilot started in August 99 and the market opened on time in January 2002.

It hasn't been without some glitches. The biggest problem that we've had in making the market work from a retail perspective is simply an information technology one.

The rules have all worked and we've been able to communicate what we're doing. We've seen about fifteen percent of the overall load and probably around forty percent of the commercial industrial load shift. Our price to beat mechanism, similar to Pennsylvania's, is the transitional mechanism from January 2002 until January 2005, when the affiliate reps can offer a price to beat rate.

We broke up the vertically integrated utility into three separate entities and built a T and D rate structure from the bottom up. Customers all transitioned Day One to the affiliate of the former utility.

We have shallower generation interconnection fees, along with postage stamp transmission pricing and ISO-coordinated transmission planning. We have a significant number of transmission projects that have been completed or are underway to relieve congestion and to interconnect new generation. Socializing interconnection costs has made it very easy for people to come into Texas, locate new plants and get connected. We have about a billion and a half dollars in new transmission investment that's either on the ground or in the process of getting built to support the market. We've taken a transmission system that was not designed to support a retail or wholesale market and have spent a lot of time and effort to make it robust enough to support our market design.

There have been cancellations, mostly, and I think not unexpectedly, in the announced and planned category. The plants that have steel on the ground I think are real. You should see reserve margins in the 22-23 percent range for the next few years.

When we opened the wholesale market, we moved from ten control areas to one and ERCOT basically took over the operation of the grid. We had a stakeholder-based market protocol process. We would probably have done things a little differently if we were to do it over, maybe getting more top-down PUC involvement early on in the process.

We have a bilateral market and what people call a thin ISO. It doesn't run a day-ahead market, only a balance and ancillary services market, very different from PJM. We've done a series of capacity auctions that are part of the regulatory framework in order to mitigate market power, where fifteen percent of the capacity of the incumbents is sold. This also is a strategy to get some of the additional sources of capacity out there. We do centralized settlement on the wholesale side and then centralized customer registration on the retail side. ERCOT is the centralized market for both wholesale and retail.

Retail customers who are served by affiliated and competitive providers moved over Day One under a price cap mechanism, at least for the customers that were under a megawatt. Larger customers received market pricing starting at Day One. The price cap mechanism provides some protection for three years and allows for fuel and purchased energy adjustments. The idea is to provide some mechanism for a link between wholesale and retail markets. By statute the adjustments only happen twice a year. It's clearly a workable adjustment that meets the needs of some stakeholders, particularly the consumer groups, for price stability, yet provides price signals.

We learned from telecom, where there are very strong protections on "anti-cramming." In Texas, provider of last resort is the safety net and the only one with the power to disconnect customers. The affiliate rep or the competitive reps of retail electrical providers can terminate customers and send them to the provider of last resort. This is probably one of the more difficult things in setting up our market structure, because we don't want that to be a competitive service, nor so high that the customers who get sent there are predominantly low-income who either can't or don't pay their bills.

The electricity facts label allows customers to do apples-to-apples comparisons and to have price transparency so small residential and commercial customers can make very quick and easy buying decisions.

Market monitoring is a function that the PUC is overseeing. The commission is very active and it is a key component.

Our system benefit fund allows some of the other social parts of the program to be implemented. We are providing 5.3 million fliers so people can make informed choices.

If we can get it to work properly, I believe the hub and spoke model is something that other states will want to emulate. It makes the cost of entering the market lower than communicating electronically with various utilities.

Right now there are about forty-five certified reps, with eleven more seeking certification. Obviously, this will ebb and flow, like Shell pulling out during the pilot – not a great thing since it had about 80,000 customers. But even if reps come and go, we want to design a working market structure so customers will be able to see their way through those sorts of things.

Interest has been growing among industrial and large commercial customers. They have availed themselves of the opportunity to switch. We have close to 200,000 retail residential customers who are involved just in the six to seven months we've been at it, without very much marketing. Our customer Web site is http://www.powertochoose.org and we are trying to keep it very customer-friendly.

Question: Who is responsible for capital formation in your transmission investment and who is building it?

Response: It's built by the T&D companies. Because Texas is an island, we don't have issues about lines going across state boundaries as elsewhere. We get them sited, approved and built in a pretty fast process. We've had the attendant landowner issues to deal with. Generally, we've made people understand that we're very flexible in where we put up a line on their land and we're very flexible in what we put on their land. It hasn't resulted in lots of litigation.

Question: Is the planning occurring under ERCOT?

Response: Planning is done at EROCT and then implemented by the T&D companies.

Question: Are there bid or price caps for generators?

Response There is a thousand-dollar bid cap.

Speaker Three

Creating efficient competition in wholesale generation that actually results in lower total costs has turned out to be complex and maybe a little harder than it might have seemed at first blush. Much of the complexity stems from the complementarity between generation and transmission: in laymen's terms, the interaction between generation and transmission. This issue was observed in the 1970s by Joskow and Schmalensee, so it's not a new fact.

Prior to competition, we dealt with it successfully through vertical integration. We didn't ignore it or pretend it didn't exist. Now the challenge is to replace complementarity with price signals so that people can make decentralized decisions with respect to generation that take into account the interaction to transmission. From a policy perspective, this is vexing because we have to get dispatch right. Recall that utilities used to handle the dispatch issue in their own control centers. Anytime they planned new generation, they looked at the cheapest alternative, taking into account both generation and transmission costs.

For dispatch, price signals using LMP are the answer. But the small problem called uplift turned out to be the largest growth industry in the market because a generator would say, "I know you're going to tell me not to run, so I'm going to schedule myself or bid at a very low price so you have to compensate me a lot not to run."

I commend FERC for its SMD white paper. Economists would say, it's going to get the static efficiency benefits out of the system, that is, the fixed generation and fixed transmission. The more interesting story is what happens when you relax the constraints: you don't have fixed plant in generation and fixed plant in transmission, but you can have investment. Have we got the right price signals there? The answer depends on the relative generation and siting and transmission costs. How do you know the most efficient place to locate a generator? If we remove vertical integration, what are the alternatives for dealing with this problem?

Option One is to let generation locate anywhere it wants and roll in the costs of network upgrades. This makes transmission free to generators and encourages siting that creates congestion if it otherwise looks cheaper to them. This will be a situation basically, where transmission and gas lines cross. You'll have generating plants, whether that turns out to be good or bad.

Option Two is to let the RTO decide where to locate generation, what transmission to build and who to charge. This replaces the integrated utility with a new central planner who sees only the transmission economics, not the rest of the generation economics.

Option Three is to send the correct price signals through participant funding., let the market decide where to locate and what transmission to build. This is the best choice if we want the most efficient outcome and it would result in real wholesale competition. And it's actually feasible, superimposed on top of SMD.

But it will not be available without SMD, which creates transmission property rights.

Participant funding is a way to fund economic upgrades to the AC network without rolling the costs into the transmission rate base that is paid by all customers under this new network service. You need LMP before you can do this. Parties can be load-serving entities, generators or anybody who has a stake in the power business. They choose to fund upgrades in return for the economic benefits they create. The benefits could be new, long-term FTRs or other property rights that are in a particular RTO, ICAP deliverability and any other kind of property rights that can get created in a market structure. They get back the value of their investment through these.

If you're a load-serving entity in an area with a limited import capability and high prices, you can get the benefit for your customers by upgrading the transmission system to get those delivered energy prices. Where there is a supply pocket where generation can't get out from under an LMP structure, the benefit to the suppliers would be higher energy prices at their bus, if you can expand the transport capability to get out.

At the time you file an interconnection with FERC, you can also ask for studies to basically create the new FTRs, or get your deliverability or whatever, at the time of the interconnection. At the same time you can see how the generation developer looks at the generation costs, transmission costs and the set of economic consequences that lead to the right decision. It requires a market-based congestion management system with a set of tradable rights. I think FERC is poised to make that available throughout the country. The funding property gets the long-term property rights in the form of financial hedges created by the upgrade, or the lower delivered price, or the higher local price. Parties may fund a project independently or jointly. If there really are local benefits that the local entity is willing to pay for, it can pay and share the costs.

But if what we're really doing is involuntarily telling somebody, "You got a benefit that you didn't want to sign up for, and now you're going to share in the costs," that's a different deal.

The SeTrans proposal describes two kinds of investment categories for planning and rate purposes. The first is pure reliability investments. that I think are called the base plan. They are the investments identified in the RTO base plan that maintain the existing capability of the grid: that is, the existing simultaneous transfer capability, Day One, or to meet load growth reliably. If FTRs are created through that group of investments, they are auctioned, and the revenues are credited to the transmission customers who pay for the rate base. In the SeTrans proposal, these go on the license plate, rather than going through the RTO-wide rate. Economic investment that expands transfer capability or deliverability, or provides network integration or whatever else you call it don't go in the RTO rates.

There are two classes. The transmission owner can build and own the facility, but if there is an opportunity for non-TOs to build and own and its permissible under state statute and compatible with the system, we call that merchant investment. Either way, the funding party gets the FTRs and any other property rights that are created by the investment.

Why is this important? It sends the right price signals for efficient siting of generation. Right now, we're telling generation developers that equipment costs, land costs permitting costs, gas pipeline and delivered gas prices matter, but transmission implications don t. That seems an odd way to promote efficient competition that is going to reduce total costs. How can you overlook a total category of costs that could be significant?

You can argue that transmission is only a small part of the bill. But the real issue is about the significance or insignificance of the transmission consequences of marginal decisions compared to marginal generation decisions. If you take five to six hundred dollars of kilowatt as the cost of a new combined cycle, we've seen generation location decisions that have transmission implications of two to four hundred dollars a KW. I don't call that insignificant.

Sending the right price signal clarifies upgrade responsibility. It avoids having local load shoulder the burden for investments that do not benefit them. It facilitates economic transmission investment. People who have an economic interest in expanding the transfer capability are able to see those investments carried, out, to fund them, and to realize the benefits, just like merchant generators are able to deploy capital and receive the benefits.

In some sense, transmission competes with generation. If you can site a generator here or there and the difference is transmission, it is competing with generation. If we get more distributed generation, it really is competing. All should compete fairly, as opposed to one player being subsidized because the transmission fixed for it is rolled into someone else's rate.

All new generators are responsible for the direct interconnection costs. Once interconnected, they can sell into the LMP spot market and get the price at their bus under standard market design. They can schedule bilateral transactions with load, as long as they're willing to pay congestion. But there's no prohibition against scheduling wherever they want. If they want congestion rights for those transactions, they can buy them at auction or in the secondary market. If none are available, they can fund expansions and receive the resulting long-term rights. This seems to be a consistent set of opportunities and obligations that result in economic decision-making, no cost shifting, no subsidies, and gets us where we want to go.

If you're going to pretend that something g costs less than it really does by making it free or by subsidizing it, people are going to act on that. Then you're going to have to put in rules or laws to compensate. The end of that story becomes more complicated and doesn't work.

Question: Who makes the distinction and how about reliability investments being identified as such in the RTO base plan?

Response: What's envisioned in SeTrans' proposal is that the transmission owners submit their plans, which are then consolidated and examined by the RTO. The documents filed with the RTO are public. They have two sections: a base plan section and a participant-funded section. The rules are that change-out types of investment – your equipment is wearing out and you can't maintain the existing set of simultaneously feasible property rights without doing something – fall in the base plan, as does load growth that you can't meet reliably from your designated network resources. SeTrans has tried to be specific about the definition of what qualifies to be in the base plan.

Question: Under participant funding, if a new generator comes on line, thereby producing value-at-risk that increases the economic transfer capability, should FTRs be awarded to the generator and act as an offset for the direct cost of interconnection?

Response: If a generator can actually create FTRs by a location decision, I think that's fair. It seems to me that the mere presence of a generator doesn't do that. It would have to be with some commitment to actually produce value-at-risk. If you're talking about a situation where a commitment is made to the RTO or whomever, if the VaR pricing itself is not compensatory, if it creates more transfer capability, it seems to me it's up for grabs. If you have a set of arrangements to create some FTRs, the person who causes those to come about should get them.

Comment: You could have auctions for people to sell reactive capability and create FTRs and get them, essentially creating an obligation on them. By existing and being interconnected, in some tariffs you already have effectively agreed to supply to a voltage schedule within certain bounds, a part of being eligible to participate. Those work at odds with each other. You could create a true property right if you took an obligation. In another sense, some of the tariffs have already taken that away as a call for being eligible to participate in the market.

Question: Who bills? Who owns? What do you do about state requirements related to certified service areas for T&D functionality?

Response: State laws will not be unimportant. Unless it's permissible and appropriate to do it on a merchant basis, the so-called participant-funded class, as opposed to merchant class, would be built, owned and maintained by a transmission owner. State siting laws, eminent domain and the like will apply to the transactions that turn out to be feasible. You don't solve all your siting problems, but when you have a participant-funded proposal that says, "I'm not asking you to pay for a project for which you get no benefits," you will get a little leg up in the siting process, unlike a proposal that wants you to pay for it but you receive no benefits and you get the structures in your jurisdiction.

Speaker Four

I was a transmission planner for many years. There was a combined generation, transmission distribution plan to serve all customers. We did not individually price components. Our goal was to get the delivered cost down. To some degree, however, we were actually in different worlds because the generation planners would ask what they needed for transmission for so many megawatts and we'd say, "Where and when?" And they'd respond, "Just anywhere, anytime. We'd tell them it didn't work that way.

The transmission planner's curse is that timing and everything else matter because you're always stuck with what was last built. You can't tear it down and start over, although it would be simpler. Something built in 1917 that's is still operational and functioning, no one will pay to tear out. There is still some equipment like that floating around in all of our systems.

There are useful parallels between the old and the new model of competitive generation and an independent transmission operation. For example, we did a load growth forecast that identified several options. We looked for transmission sites usually inside our territory, but sometimes outside of it. We stacked the alternatives together as whole groups: one plant, its distribution, its transmission consequences, another one's, and so on. The test was the used and useful concept. Then we went to the state regulator with our best choices.

In the new expansion process, it's important that we have the same sort of thinking process, even though we're not breaking out the components. Today, the load growth estimate is being made by the local load-serving entity. It's called RAP in Texas, or it could be the traditional utility in a state like Idaho that doesn't intend to go to retail access. They've got to build a resource portfolio. For that, they need a separate price for the transmission and the energy. They make their least-cost supply options; the demand side or distributed options will be there. For hub and source purchases, will they buy a bloc of energy from someone? In that case, they may want to own the transmission right, or the buyer may want to. Or the seller may want to own it in order to make a delivered purchase.

Formerly, we just thought about supply risk. The last few years have taught us that we have to think about price risk as well. So we're going to build a portfolio of assets and resources to meet the need as a load-serving entity.

Should the regulatory oversight be the adequacy of that portfolio done at the state level? It seems to me that the state that is licensing people to serve at retail, either in an open system or in a closed one with a franchise, should be looking at this resource adequacy. This is not unlike gas distribution companies that in some cases never owned production facilities. Does the state or the RTO decide what the generator adequacy test should be?

The grand question in planning always is how much for the common good and how much for specific parties. In other words, what goes into rate base? It's difficult to answer that question.

Transmission expansion driven by generation siting should show up in the price of energy from that source. Some people say that generation competes with transmission. What we're really talking about is transmission plus remote generation competes with local generation, or combinations like that. How do you break up the costs? Do you have an interconnection fee as an impact fee up front? In resort areas where there is a lot of new home construction, the impact fees mean that you pay for the water, sewer and other systems up front, rather than funding it out over bonds and shifting it to the other members of the community. If that's the case, how much interconnection should there be? Enough to reach the backbone, or should it reach clear to the nearest trading hub?

Particularly with the hydro in the northwestern United States, there are questions about remedial action schemes and their costs. These are situations where the rating of the line can be held higher pre-contingency if you dump generation when the contingency occurs. For example, the Pacific inter-tie rating is currently based on the fact that if two of the three ACs trip at the same time going to California, they dump a bloc of generation and hit the brake for a few seconds and then pop it off. By dumping generation, the other machines gradually pick up and you actually can hold the rating up higher. If you are dropping thermal generation in one of these schemes, there is more risk because of the risks in your boiler. There is generally not a great deal of risk in hydro, but there is wear and tear on machinery and equipment and concern about what happens if you have to replace the energy for the time that your machinery is out. These are probably the cheapest things to do, rather than build new rights or way and put new conductors in the air. Some expansion costs are very difficult to target to people. They may require some common funding, but they should be in a base plan and you can generalize the load growth.

Once I worked on a project to build a new line in a valley in Utah. The locals said that the new steel plant in the area should pay for the whole line. But before the new plant located there, load had been growing gradually. All of the local transmission needs needed to come up.

Another problem is the best use of corridors. I don't know of any major line you can build in the west that doesn't cross federal government territory. For example, when you are using federal lands in a corridor, it may be that you are going to get one line through a mountain pass or a significant area. You propose a 138 kV line, but someone says that it has to be at least 345 kV because you will be unable to use the same corridor again, and therefore it should be funded at the higher level. The party willing to fund the lower voltage line lacks the economics to pay for the higher voltage line. Should it be for the common good?

To solve this problem, you need open planning, decision-making and dispute resolution processes within an RTO. An RTO should inform all participants, anticipate their needs and provide a set of known design constants. Sometimes a board must make "split-the-baby" decisions. For example, if the board determines that some costs will be borne by one company and the company disputes the decision, you need to resolve that and any appeals to FERC. And regional variation is important. Geography and topology really do matter in transmission systems and are unique to every location.

There is a problem with existing rights. It's one thing to say we're going to have an auction and give you the proceeds. That assumes that the proceeds produced by the auction match future congestion costs that you will experience. There may not be a match at all, especially in the system startup. We have concluded that you can define even the contract path rights as injection withdrawal pairs, or source sync, that in point-to-point was point of receipt to point of delivery and in some cases to trading hubs. We had networks that could be identified. The service wasn't solid strips, but was shaped. At least in the northwest, it had optimality that worked around seasonal variation in the hydro system. Because of the shaping and optionality, it is difficult to turn that into solid strips of FTRs that are for example, annual strips, or even six-month strips. The mapping is easy but the hard part is matching up the optionality characteristics of the existing rights. If we were to put in all existing rights as solid strips, we'd be massively over-allocated. Using pro rata reductions to resolve the over-curtailment means that a substantial cost shift takes place because even if you prorate them down, they don't have the same protection that they used to have at certain times and didn't need at others. At the same time, the physical system has been able to honor all of these things with minimal congestion and cost. We do need a way to take care of the diversity.

RTO West has put together what we call a catalog transmission right. CTRs are a way to pool the options for the existing financial rights to leave them with the shaping and to allow more FTRs or options to be issued. We go through all of the current contracts and obligations to identify the injection and withdrawal points, the limits on simultaneous usage that they currently have and the timing restrictions. To the extent that each participating transmission owner has issued these rights and has to use some re-dispatch or some remedial action scheme or other activity, all will be treated as assets they have to bring forward. We'll banish the obligations and match it with the asset that the owners have to bring forward. If in an aggregate test they all come together, we've met the test. Then we'll propose to release any additional capacity as transmission options. The CTRs in effect compress to the minimum set in any given time point what we have committed going forward because we're trying to capture the diversity in use, while still being able to honor the existing rights. There are provisions for people to pre-schedule and release those into an auction.

The existing rights are important because Bonneville Power Administration is not subject to FERC's general jurisdiction, and BPA's participation is a key element to the success of an RTO in the northwest. Bonneville has said it can't participate unless the existing rights are honored.

If we can get nodal pricing of congestion and imbalance and losses in place and people understand and get used to the pricing and settlements, then things like fixed cost recovery can be pushed off to the future. Don't try to solve the license plate problem up front. Allow some reasonable adaptation for the conversion of existing rights and show people how this works for them. There are no winners in fixed cost recovery fights, so don't fight. As understanding grows, expand the energy market. There has been a very active bilateral market; people are used to trading energy hourly with one another. Now you have to show them how your model has additional value. Put it in place, let it run and add other features in time.

We have a vision of getting to a single market. We have learned that when prices rise in California, everybody in the west gets hurt. There is no insulation. But the fact that there's only one market doesn't mean you have to have a single operator. How much system can a single operator really pay attention to? Aren't you better off to have some division? There is also diminishing return as your scale increases that doesn't necessarily mean increased savings.

Another key issue is the timing between markets. When California first started up, the northwest market closed before California fully closed. While this problem was simple to fix, it did need to be taken care of up front. There are unresolved issues about flow and transmission rights between parties. And almost every RTO has a through and out charge or export fee that should not be part of your efficient model. But if you are the beneficiary of taking money in, suddenly surrendering these fixed costs is not a great solution.

Finally, if we think we know the answer to the solution because we know the problem, we need to keep asking if it is the right problem. There has to be more adaptation possibility in the system as we go forward. We can't just rely on NOPR because it is too slow.

Question: If you don't see the congestion, even though as a strip you would be over-subscribed, there is a time step at which these options are valuable to someone and not valuable to another because of diversity. Is it a daily issue?

Response: Yes, because of hydro you can get into spill situations and other circumstances.

Question: Does the absence of a day ahead market in Texas work against FERC's desire that RTOs and ISOs facilitate and accommodate demand response resources?

Response: I think we have a natural market for demand responsiveness. We have a valid schedule requirement in the way the market is structured that allows the retail electric provider to include that in its portfolio. I'm not sure that the absence of the day ahead market is at all a hindrance.

Response: A day ahead market will help us reach the goal of resource neutrality and treating the demand side with the same respect that we treat supply.

Question: The complementarities or economies of scope between generation and transmission suggest efficient vertical integration. The view held by most people is that maybe even an absolute legal separation between generation ownership and transmission ownership is needed for market power concerns. Are we setting up conflicting policies?

Response: You can't go to competition in generation without acknowledging the complementarity and substituting for it. Properly constructed price signals – LMP for the static and participant funding for the dynamic – can enable the separation that FERC and others are advocating.

Comment: In New York, acknowledging the complementarity exists in FERC-approved tariff language and is partially in the PJM tariff with respect to new generation. It's been approved piecemeal for some merchant transmission projects that have come before FERC. New York in particular has made great headway in the implementation process for both AC and DC rights. SeTrans is looking at New York.

Comment: In today's environment, transmission lines may be hard to site. What you've proposed should work well in states that have rules about least cost, or showing a specific benefit to customers.

Comment: In demand side bidding we haven't taken into account that under state regulations, there is a question as to who owns the power. In the aluminum industry, you had take or pay contracts; and therefore, a property right that they could sell, while steel plants only paid what they took for that month and so had nothing to sell. Until you clarify that property right at the state level, it's difficult to know how to get people to bid.

Comment: The most important distinction is the balanced schedule issue. I think FERC has decided not to have a balanced schedule requirement because that drives you to a day ahead market and a more generalized demand side opportunity.

Comment: Balanced schedules may change how you look at planning. Right now, your planning model looks at LSE by LSE. Where we didn't have balanced schedule requirements, we now have to look at an aggregate forecast. It's usually the distribution company because the LSEs have every incentive to under-forecast and to under-build. We had to actually shift that when we no longer had a balanced schedule requirement.

Question: Are FTOs, the point-to-point options easier in the northeast?

Response: They may not be easier computationally, but it's what the market wants. They have already been given out historically as sold rights. They are sold and they are options. If you're going to map today's existing transmission rights into these new FTOs and you try to map them into FTRs, you can map the locations, but you can't map the coverage because the fixed strips, even if you make them hourly, variable, don't quite apply. How do you deal with three injection points in one delivery? How do you spread the megawatts? We're trying to go to financial rights in a nodal locational marginal pricing model and then somehow emulate what exists. As you solve this computational problem, the risk of under- and over-collection can be higher with the options. The market participants say that's what they want because it's the way they run business and want to continue to do so.

Question: What would it take to convert them to FTRs?

Response: They don't convert easily. If all of your flow is in one direction and you knew what was going to happen, maybe you could live with the obligations because you assume they would never reverse on you. But when you have seasonal diversity and other variables, people are leery. If the options can be made to work and if that's what the market wants, you can now sell the spot market and you can lash up with the existing forward market. The reason for a forward market in a hydro system is that people are selling energy for next month based on storage. If we take options away from them and say, "No, you have to have obligation FTRs," then we get a fistfight and a political effort to try to extract Bonneville from the RTO.

Comment: To meet the grandfathering objective of giving people what they want, you have to reconfigure their rights with great frequency.

Comment: Somebody who gives people those transmission rights has taken on the responsibility to re-dispatch. There is an embedded obligation on the part of Bonneville to provide the counter flow that is not provided by the obligation because they have an option. You can't call these options and not have Bonneville responsible for the counter flow and reproduce what you have today.

Comment: There is an annual adequacy test to make sure that they brought enough to the table.

Question: Then the uncertainty is about how or if Bonneville will be able to honor its counter flow obligations?

Response: No, we take the CTRs and this pooled set of options and test for adequacy and we think that's okay. Now other people want to use the system so we have an auction. We have to decide how may more options we will sell, just like you do in an FTR. That may engender some additional risk of over- or under-collection from year to year, or they may miss a high or low one year.

Comment: You have to make sure that you are not selling a call for a third-party use of the system for Bonneville to re-dispatch outside of what you've done historically.

Response: That's why you take the existing assets and obligations and match them up. Then you ask what you can sell beyond that. There is some risk of the RTO making a mistake on how may to issue or not. Maybe it's two or three percent. If you think it's bad, you call it socialization and if you think it's good, it's the common interest.

Question: Is this a transition mechanism or a permanent design feature?

Response: The CTR is transition as long as those contracts are in place. Given the length of some of the contracts, -- some are for thirty years – you may think it's permanent. If the model really works and people become comfortable with it, you can take another look. Whenever somebody sees an advantage, they'll migrate quickly.

Question: Point-to-point is an option being requested by market participants. It's been described as an extremely risky, short-term product that lacks a strong market. Who is interested in procuring this product since the technical feasibility is somewhat questionable?

Response: We have a constant flow of people into this industry, so basically, it's the newcomers. As long as you have a process where people can get educated, most will probably decide they don't want them. If it turns out it is feasible, then let them have them. However, if you say it will work and won't be too risky and it turns out to be the opposite, then the pressure to socialize that, and I mean it in the bad sense, is going to be very strong. It's easy to say in documents that this is the market's risk. It is another thing if you've over-promised what you can deliver.

Question: To what extent does creating an ADR to resolve disputes with an established RTO represent a philosophical approach on the part of FERC?

Response: Disputes must be resolved as close to the problem as possible. If that requires an alternative dispute mechanism, I'm for it. If FERC needs to get involved with some sort of FERC-ADR mechanism, it should be the backup.

Question: We have talked about a standard market design with bid-based dispatch priorities with grandfathered contracts. At the same time, we have merchant transmission that gets physical rights. Can the physical rights be accommodated if they are connecting two markets together? Can they be accommodated if they are HVDC? If we try to get rid of the grandfathered contracts over time, we are creating a new set of contracts with merchant rights that could have different physical characteristics such as HVDC. An example is a merchant DC tie between two regions. The right holder paying for these merchant rights is debating how to schedule priorities. I define that as a physical right. Is it acceptable for the right holder to have the priority?

Response: If we had standard market design and could define the rights, the merchant could convert its rights into the new definition. If you don't have the standard market design in place and you don't have financial rights between somebody else, then the people coming in will ask for something within the existing framework. Getting locational pricing and financial rights is absolutely critical to the success in the long run of the things that merchant transmission owners want to do.

Comment: The notion of withholding because the owner of a DC line can schedule it itself is a false issue. The owner has every incentive to arbitrage as fully as possible between the systems. You have to make residual rights available. My view is that you don't have to allow anybody to reschedule them. You don't have to release them. But with an AC line, the rights structure and everything else are critical and you cannot withhold.

Question: People have argued that ICAP is a product that is needed for reliability. Some regions have a deliverability test, which is the capability of delivering aggregate generation to aggregate load. Would upgrades needed for that purpose fall into the reliability need or participant funding?

Question: Are the upgrades necessary to accomplish deliverability from a particular new resource?

Response: Yes, but the test is delivering aggregate generation to aggregate load.

Question: Is the test being applied to a particular generator that wants to qualify as ICAP?

Response: Yes.

Comment: There are transmission investments required for them to meet that test. That would be participant funding because in meeting any reliability test, we haven't said that we want to socialize those and have only the RTO acquire ICAP. We said the markets are going to supply ICAP. If you are going to have a market for ICAP, then the transmission implications of using one generation resource versus another also has to be in that marketplace. If you have a model where reliability is going to be socialized and the RTO is the sole provider of capacity in ICAP, that's not in place in any of the markets that have installed capacity obligations.

Question: How do existing generators get the right to sell ICAP?

Response: There is another grandfathering question in terms of deliverability of the current system. Those rights need to be defined, as I believe PJM is doing. They ought to be tradable rights, too. It makes more sense to qualify a different resource than the one that currently ahs the rights. I t should not be a "use it or lose it" type of obligation. They should be reconfigurable, in the same way we want to reconfigure transmission rights. Then you will get a competitive solution to that problem, too.