Harvard Electricity Policy Group
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RAPPORTEUR'S SUMMARY*

Session One: Commercial Incentives and Reliability Rules

The U.S.-Canada Power System Outage Task Force Report provides interesting reading. There are 46 recommendations, identified with four broad themes: mandatory rules and market incentives; no free lunch; act now; and this is important. A closer look finds that, "[T]he need for additional attention to reliability is not necessarily at odds with increasing competition and the improved economic efficiency it brings to bulk power markets. Reliability and economic efficiency can be compatible, but this outcome requires more than reliance on the laws of physics and the principles of economics. It requires sustained, focused efforts by regulators, policy makers, and industry leaders to strengthen and maintain the institutions and rules needed to protect both of these important goals. Regulators must ensure that competition does not erode incentives to comply with reliability requirements, and that reliability requirements do not serve as a smokescreen for noncompetitive practices." *(p. 140) This is a major implementation challenge. Other than pinpointing the need for something better than TLR curtailments, the details are left to future study. How and where do commercial incentives conflict with reliability? What can be done to reduce or remove the conflicts? How can a priority for reliability be implemented? How is this tension different from or separate from the continuing debate over markets and market design? If we are to act now, what should we do?*

Speaker One

Broadly speaking, we can de-rate the grid aggressively, making sure that the rules on commercial activity are so conservative that excess capacity exists at all times so that the system is never stressed, or we can try to use the grid's capacity efficiently and economically. In an almost deductive process, we know how to characterize efficient use of the existing capacity in the context of a constrained grid. That characterization implies several things, but it t urns out to be equivalent to the security-constrained economic dispatch that produces the consistent prices in differing locations that provide incentives for short-term operations where people make trading and dispatch

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

decisions that are related to short-term reliability.

Any time you adopt another pricing system you create a commercial incentive and problem that may have reliability impacts. Obviously the preferred solution is not to create such problems. Frankly, I think it is almost impossible to design a system that is consistent between the commercial system and reliability rules other than this one, although I cannot prove it.

As I read the task force report I realized that it meant we could also understand why SMD has such important implications for short-term reliability.

Speaker Two

I view reliability as an element of the bigger restructuring picture. There has always been a tension between regulation and antitrust in the electricity industry, almost to the point where antitrust has taken a back seat to regulation because of its pervasiveness, and because of the different standards of analysis in terms of performing competitive and market analysis between the two sides of the business. Now we are at a fork in the restructuring road and we can go in one of two directions.

One direction is command and control, with a very strict, pre-determined set of specifications for how reliability will be accommodated. The implications for that are more regulation and less antitrust. The other direction is competition policy, which implies less regulation and more antitrust, or enforcement of the competition laws.

There are some key distinctions when we look at product quality and electricity in other industries. Product quality is an element of non-price competition. Consumers often pay for the level of quality that they prefer because they can distinguish it. And in the absence of information about quality, there is always the "money-back guarantee."

Electricity is quite different. We have a system of command and control reliability under the present competitive model, but we also have transmission bottlenecks that render the system blind, or unable to process or deal with any quality-based competition at the generation level. Even if consumers could respond to quality differences through a system of different prices or choices in the programs they sign up for, command and control and the bottlenecks make it very difficult to implement that objective. Electricity consumers are assumed either to be completely similar in their preferences for reliability – which is probably not true – or for some reason, we cannot segment them into different parts or different types of demand, which would reflect different reliability preferences.

Another issue is setting standards. Obviously, standards arise because the costs of not having them are very high. Standard setting is often produced in a coordinated fashion so the tradeoff is between the standard you get in an atomistic competition versus those in a coordinated process. In most cases, governmental or quasi-governmental independent bodies administer the standards externally. In contrast, electricity has many command and control standards. Such voluntary, non-independent standards, along with unenforceability, unresolved reliability and supplier liability issues reflect the underlying issues of the major stockholders.

There are three things to consider when choosing reliability policy instruments and deciding on the optimal blend or mix of command and control and market-based or competition-based instruments. One is to recognize policy equivalency. For every command and control instrument – whether TLR, resource adequacy requirements, or bid caps – there is either an equivalent policy instrument on the competition side or a set of instruments to accomplish the same objectives, but with the benefits of market reform: lowering concentration, easing entry barriers and increasing demand response to inject some discipline in the market.

The second is to reduce bias toward command and control. The historical engineering-based approach that we have will create a powerful force and perpetuate a system of heavy reliance on command and control instruments. We must be aware of how that force drives the process.

The third is to avoid interim or stopgap policies that do not commit to market-based, competition or command and control approaches. Going the stopgap or interim route has not turned out to be particularly successful, as we have seen with market-based rates and Section 205.

There are several fundamental components of command and control reliability. TLR is probably the most effective way right now to deal with congestion, but it increases the risks of regional transfers and the prices and costs to consumers. Having information on the buyers and sellers in a contract can provide tremendous incentives to behave anti-competitively, but the flip side is that the information is critical from the perspective of transmission planning and management. Bid caps distort consumption decisions and investment incentives and repress development of new technologies. They ignore load pockets where you might need different bid cap levels in small markets. They require ongoing fine-tuning and revising that account for the relationship between the cap and the incentives. Although FERC has been clear about its willingness to entertain regional differences and approaches based on physical differences in the grid, what about economic differences, differences in demand components and differences in technology deployment? I think more than physical differences should account for regional variations. Finally, resource adequacy requirement is another component of command and control.

The elements of competition-based reliability include demand response – injecting more ability for consumers to respond to high prices by reducing consumption, and the programs can be bid in to ancillary markets as a form of reserves; LMP greatly reduces the need for TLRs; designing a hybrid model RTO that provides good incentives, especially if legislation never actually separates generation from transmission; independent reliability organizations; disclosure requirements for consumers so they can make appropriate decisions if they are cut off at some point from a free-riding LSE; and the elimination of preference for native loads.

In recent years, antitrust has had much to say about standard setting, which is really more about process than structure. This process should be an open one that includes buyers and sellers to avoid collusive or anti-competitive outcomes. The temptation is to create over-reaching standards, or ones that are overly specific. Performance-based standard setting is a way to avoid some of those problems.

Year after year, antitrust agencies have pushed in every FERC rule-making for structural reforms FERC is more likely to pursue the compulsory access or the forced access approaches and behavioral rules, which will perpetuate what we have now. Any mix of command and control and competition instruments should reflect the legal, economic and institutional characteristics, not just the engineering.

Another element in the balance and tension between regulation and antitrust is to identify and prosecute the exercise of market power. Antitrust can do much about exclusion under Section 2 of the Sherman Act. But antitrust is not equipped to do anything about what I call classical market power, which is strategic withholding. FERC and the states must resolve that issue.

Another element is maintaining coherent merger review. Traditionally in a merger review process, reliability is handled in the form of an efficiencies defense. If there is a separate reliability impact requirement in FERC merger review, it will wreak havoc not only on the review process that is guidelines-based, but also on the tension between the public interest standard that FERC enforces and the "no harm to competition" standard that the agencies handle. I think this is a huge issue. Both regulation and antitrust should consider the full complement of structural remedies -- not only divestiture -- but transmission expansion and rights allocation.

The approach to market analysis includes resolving inconsistencies in analytical standards. Some state commissions are very anxious to get formerly unregulated generation back under the utility umbrella in the name of reliability. Many transactions are sliding by state regulatory review or are in an expedited process because of reliability motivations. I think how they are evaluated from a competitive standpoint is very important. The inconsistencies across 203 and 205 are very alarming.

The logical conclusion is that if you want consistency, you should probably take a guidelines approach so that it all is analyzed the same way, with some variations, but the principles are basically the same. Looking at market share and concentration does not work very well in electricity markets. Finally, we should begin to push harder for the use of simulation models. We should perform ongoing market analysis, not just doing it once a year or every two years. I know FERC is pushing in this direction.

Comment: Customers who want power quality, can install on –site backup generation.

Response: Detailed empirical studies of willingness-to-pay show a disconnect between what consumers are willing to pay for reliability and how they actually estimate the costs that are imposed on them. I think getting reliability under control means more than addressing the supply side through TLR, bid caps and reserve requirements. It means developing and putting into place pricing mechanisms, technologies and metering to open up the ability for consumers to alter consumption in response to price differentials and price volatility. This has to come from the states and other initiatives.

Question: What is wrong with FERC looking at the reliability impacts of a merger?

Response: I think there is some tension in merger review between the regulatory and antitrust sides. FERC has a public interest standard that allows it to consider more than just a "no harm" standard or a "no lessening of competition" standard. What I am saying is that that tension will be potentially exacerbated if there is no ad hoc reliability impact requirement. The purpose of the guidelines is to weight potential anti-competitive effects against any sort of efficiency enhancements or gains that would flow from a merger. Depending on how much weight FERC wants to give to a reliability impact requirement, it could disturb the very natural balance that the guidelines set up in evaluating mergers. The mergers that FERC has conditioned and that the FTC and DOJ have been involved in have been vertical mergers. Because of reliability concerns, I think it is very likely that there will be a strong push to defend potentially anti-competitive transactions on the basis of reliability.

Speaker Three

We have always taken reliability for granted. The local utility has taken care of it. It runs a cost-of-service case for its native load customers, goes to the state commission and it is all done. But reliability has costs, now that we have to live by standards.

We will need observability to maintain reliability. We will have to plan for reliability, to account for loop flows and other things that have not been done. We will need reliability overrides at the point when we run out of controllability and people act according to the price signals. There must be a traffic cop to get the system back into a secure condition. We need also a circuit breaker like TLR. Having said that, the problem I see with TLR is that it has become a reactive tool. It happens after the fact. There are also modeling and threshold issues. Until you get to dropping load, all TLR is gross redispatch. I believe NERC has said TLR should be the last resort.

When markets exist, generators can react to price signals. There is controllability and you do not reach your operating security limits. Market participants have economic choice.

Why is it that everyone has not adopted a market-based congestion system? The biggest issue is cost allocation. An example is Alliant West, the control area of the Alliant companies in Iowa. It told NERC that it was receiving a lot of firm TLRs, that a lot of non-firm continued to flow and that the distribution factor was below 5 percent. Alliant West said it was unfair that it had to curtail firm transaction when the non-firm was flowing. When asked why it did not redispatch, Alliant West replied that there was no mechanism to spread the cost of redispatch and that it was too difficult. Transmission providers may also tell you that they refuse to do something because it will cost them money or revenue and that they have no mechanism to pass it on to you, and therefore all transactions should be curtailed.

Would a market have prevented the August 14 blackout? Maybe. If everything had been working right, if everything had been tested, as soon as the East Lake unit tripped and the flows began increasing from the south, you should have seen LMP go up in southeast Michigan and go way down away from Akron/Cleveland. However, trees had grown onto lines when those lines were not at their rating limits. In that case, the algorithm would not have said to redispatch because it would have thought everything was fine. The lesson is that the model must be really good and the state estimator has to work. The line ratings and equipment ratings have to be correct, and as we all know, trees have to be trimmed.

Allowance for regional variations needs fixing. I believe the variations should be as minimal as possible and justified solely on the basis of reliability. I think they have been used for too long for either protectionism or as a rationale that there is no reason to change the way business has always been done. An example is that we still lack a standard way of calculating and decrementing ATC in the eastern interconnection. NERC has directed companies and regions to do this and yet there are companies that change their ATCs when they receive requests. Other companies do not change the ATCs until they receive acceptance or confirmation. I think the latter is in line with the NERC-accepted rules but the two are simply incompatible. It does not allow the best, most efficient use of the network.

There are some different practices in the use of the network that must be fixed.

RTOs and providers cannot have rules that are inconsistent with reliability or with markets. Everyone knows you are not supposed to overload the network, and that includes your neighbor's network. Whether you go by NERC's rules or interconnection agreements, this has not been respected for a long time and there is no sanction. The basic ground rules must be the rules of the road because as we saw on August 14, commercial transactions do not work very well when the frequency goes to zero.

Outside of Texas, no RTO is an island. We need coordination of ATC. We need mandatory protocols for the exchange of information. We need mandatory reliability rules. We need sanctions for enforcement. We now that all of these things are not new. The real problem I see in a competitive market is how to resolve them in less than 3 years and still maintain due process.

In the absence of energy legislation, FERC has taken the bold step of including NERC rules in the tariffs as part of good utility practice. That takes care of the transmission providers, but there are other users who may not be subject to NERC rules. FERC has not gone back and amended old interconnection agreements that may lack those provisions.

I think markets are good for reliability. I think they are compatible for reliability. But right now much of the infrastructure is a little shaky.

Speaker Four

August 14 occurred because the rules that have been in place for some 60 years and that are understood by those who plan and operate the system were simply not followed. No matter what kind of standards or markets there are you will have problems if you do not follow the basic rules for operating an interconnected electric system. When it comes to what we call the security of the grid or the stability of the grid, in my opinion as an engineer, there really are no market mechanisms that can address some of the deficiencies.

The immediate causes included: the lack of situational awareness that existed, the failure to manage tree growth and the ineffective diagnostic support. ECAR failed to assess and understand the inadequacy of FirstEnergy's system, particularly with respect to voltage instability and reactive power resources. The utility itself could not see what was going on because of the failure of its critical computer systems and it did not have a dynamic map board in its control center. MISO and PJM did not have the communications systems in place to provide effective real-time diagnostic support to properly coordinate the reliable operations.

In February 2004, NERC's board approved a number of recommendations to address the blackout, and to take some actions that would mitigate or prevent future cascading blackouts. It adopted four strategic initiatives: strengthen its compliance program; initiate readiness audits; evaluate vegetation management practices; and develop a more formal tracking mechanism.

NERC is developing a set of more specific compliance templates so that people will know without question what it means to be in or out of compliance. It is also accelerating the adoption of reliability standards by translating the existing polices and standards, along with the compliance templates, and several new standards that are either under development or in place, into an integrated, comprehensive set of measurable standards consistent with the terms and definitions in that functional model. NERC expects to have this so-called "Version Zero set of standards in place and approved by its board by February 2005.

NERC has also made some immediate revisions to several operating policies to clarify the functions and responsibilities and authorities of reliability coordinators and control areas that were not clearly understood and adhered to on August 14. It has approved a set of disclosure guidelines for reporting violations of NERC reliability standards and the results of its readiness audits. These audits are similar to the evaluations of nuclear plants conduced by the Institute of Nuclear Power Operations. NERC will conduct its on-site audits at all control areas and reliability coordinators over a 3-year period on a 3-year, continuing cycle. Eventually the peer reviewers will be permanent employees. FERC and Canadian regulatory personnel have accompanied NERC's reviewers. By the end of June 2004, 21 audits will be completed: the final reports will be posted on the NERC Web site.

For future readiness audits, NERC may give priority to organizations that are undergoing a merger, to make sure that the merged entity retains all of the reliability capabilities of the individual entities and maybe improves upon them.

NERC has developed a vegetation management compliance template for transmission owners to report vegetation-related outages. Following its 1996 blackouts WECC adopted a similar program that has proven effective in reducing such outages. It is also developing a vegetation management standard.

In association with DOE, FERC and Natural Resources Canada, NERC is building a database to track key milestones for the 46 recommendations and their subsets. It wants to do a better job learning from the lessons of past blackouts, where some of the same lessons and problems have been repeated.

In addition, NERC has nine technical initiatives for which it is developing options and recommendations. One is operator training. It is talking with FERC about a broader study on operator training and certification.

There are other violations beyond the ones in the task force's final report. NERC will vet those through a process before anything is disclosed publicly. Finally, NERC will not wait for legislation, but will do everything and anything it can to put some teeth into its standards.

Question: To what degree were reactive power issues on August 14 significant?

Response: On August 14, reactive resources were not managed effectively. The East Lake 5 unit tripped because the system operator called for the plant operator to increase reactive output. In the process of doing that, they lost not only 600 MW but also 300 MV and at that point were in a severe reactive deficiency. NERC is considering the possibility of using automatic undervoltage load shedding so that if you get into a voltage collapse situation, you can save yourself by quickly tripping some load. The system did not collapse due to a voltage collapse, but if it had not been for some of the Zone 3 relays opening up lines, it could have. It was a race to see what was going to take the system down first. Voltage was there, but the depressed voltages in the area, along with the high current flows, got inside the relay circles and caused some of the apparent relays to trip and open up circuits prematurely when they were still well within their rating.

Discussion

Question: Notwithstanding the fact that everyone is asking for mandatory reliability standards, what is the role of peer pressure?

Response: Generally, peer pressure is good. But most systems are not the kinds that are as brittle as the electric system can be. Many of the people who work in control centers are very conscious of their public responsibility and have a strong ethic and cultural bias that is quite different than the commercial interest of the narrow parties. But I am not confident that this ethic will last forever.

Question: Why do the regular reports to the NERC board need to be confidential? How does that contribute to more transparency?

Response: To give those accused of a violation a chance to defend themselves or explain themselves before it is posted on the Web site and made public. There will be transparency but also some due process.

Question: A control area is called that because of the control. Anytime that control is not in the hands of someone who is not independent, you have at least the possible occurrence of improper control. When you couple that with native load priority in the same hands, it really becomes cold language and equal to the ability to discriminate. The legacy of the large number of control areas is foundational to some of the problems we have seen in the industry. What do you think?

Response: There are too many control areas. The Midwest has some control areas the size of 500 or 1,000 MW and there are also some generation-only control areas that existed to fully comply with the existing NERC rules and to take advantage of control area status that means that some of the rules were broken. I think it will cost money to make the transition to fewer control areas. But absent any real direction and objective standard about what should be done, I think inertia takes over.

Response: I believe that the EMS systems, computers, displays and other things in these centers have a half-life of 4-5 years in today's technical environment. If it were likely that many people will be upgrading, that would appear to afford an opportunity to save money by doing it once a little larger, rather than upgrading three centers, for example.

Response: People are very comfortable controlling their reliability and their balancing. I think it takes a major leap of faith to combine control areas and put them in the hands of another party. It has to be clear that the new operator is well qualified and that reliability will be maintained.

Response: As we move to a restructured environment with more competition and markets, the way the old rules are written does not make sense. That is why NERC is making the transition to its new Version Zero standards. Nonetheless, there are still entities that see commercial advantages to being a control area because control areas enjoy some scheduling advantages over non-control areas.

Comment: From a competition policy perspective, larger markets in a regional RTO setting are better than smaller markets for the reason that it expands the system and reduces concentration. I think FERC has many tools, at least on the regulatory side, to look at efficiencies related to control area consolidation.

Question: How do you make prices efficient in the long run?

Response: Getting the prices right is just one thing. How can you make them politically acceptable in the context of rent transfers? To the extent that you can get the regulatory system to withdraw, if not disappear, it is easier for people to let the normal operations of the markets work. It becomes difficult, though, when regulators must intervene because of pricing movements in the very short run.

Comment: You could view the restructuring experience to date as an experiment in how willing consumers are to pay. But I would put more weight on the demand side and an integrated demand approach, not only at the wholesale level in terms of the ability to shed load, but transmitting those signals down to the retail level though real-time pricing and by implementing metering. You cannot have a market-based system without price volatility and we struggle with how much volatility is politically acceptable.

Question: Does NERC accept the premise that reliability should be pursued and is it fully aware of the commercial incentives that market participants have? Is it trying to incorporate that premise in the remedies and proposals to enhance reliability?

Response: NERC worked with the North American Energy Standards Board to develop the Version Zero standards. NAESB is paralleling NERC's effort to develop companion business practices to go along with each of the new reliability standards. A set of reliability principles and market interface principles are spelled out in the NERC standards process documents for each new standard that is being developed.

Question: Did liability requirements have any impact on August 14?

Response: I am not sure that liability rules would have changed anything. I think things still have to play out. One remedy that could be useful is to look at Illinois where utilities that serve greater than a million customers and serve the load in Cook county, can be penalized under state law if a certain number of customers are out for a certain period. Depending on the enabling legislation, it could be done by utility commissions without going to the legislature.

Response: There must be a balance between who is held liable and what can be insured against. I think operators need to be held to some level. But right now, at least for state-regulated entities, states are one way to deal with substantive issues.

Response: Liability goes hand-in-hand with property rights. There must be a way to define and enforce these rights with clearly specified liability limits and collection of damages. This policy question and core issue should not be resolved in an ad hoc legal context. It needs guidance from FERC or NERC or a combination of the two.

Comment: Most states have minimum electric service standards but they are restricted to activities within their state borders. It would seem to me that the report itself would be difficult to use in litigation because it cannot be part of a record – there is no one to cross-examine.

Comment: I have suggested that electric utilities offer provider insurance as an extra to their customers. But this raises the moral hazard issue. If a company creates a few more outages, it may be able to sell more insurance. The opposite perspective is that if it sells insurance, it will be more careful. The difficulty is the free rider problem because a utility cannot differentiate between its insured and non-insured customers. I have been told that there are ways to do so. You could target large customers so as not to shut them off in certain situations. An insurance system would at least give you some idea at isolating the demand for reliability.

Comment: You can deal with supply adequacy on a demand response basis – putting in self-generation, interruptible loads, liquidated damages contracts and the like. But the point this is overlooked is the stability of the grid. On August 14, New York and Ontario customers did not pay for any lesser level of reliability, yet their lights went out. There are two very different aspects of reliability: the security or stability of this interconnected system, and the adequacy of the supply, including the delivery system. You may get to a point where the market no longer has the ability or the capability within itself to address the issues and you have to be able to resort to command and control standards so the system's stability remains intact.

Comment: It is wonderful to get the price right for short-term congestion, but that by itself does not solve a lot of the problems. An example is that from an antitrust perspective, not getting transmission built is in some cases protectionist and people maintain their market power. When you have outages, you have the inability to define property rights. In the Midwest right now, Manitoba Hydro does not have water; the flows on the system are totally reversed from the way it was built, and it is causing security problems, not just market problems. Another example is a company that builds a line that is not in its service territory, yet its customers will pay for that construction. You can be supportive of the market but do not let the focus on market design get in the way of doing some of the other longer-term things.

Response: A regional planning process should identify what is needed to serve the load reliably. It is the base system that must be built and there are rules about who pays. But it should not be socialized: those who benefit economically should pay. Some of the griping about an inadequate transmission system is really about not being able to bring in cheap power.

Response: Access pricing as a policy issue has more prominence in other industries than in electricity. FERC's numerous transmission policy-pricing statements over the last several years have not really gone anywhere.

Question: We created a lot of inefficiencies in siting when we de-integrated, some might say disintegrated, siting of transmission and generation, and with Order 888. How would a successful market design for transmission pricing solve the inadequate transmission problem for existing generation assets?

Response: Solve the short-run problem first and then deal with the long-run problem because it becomes quite different when you change the short-run pricing rules. Have an investment regime for transmission that is compatible with a hybrid system where people can make merchant investments based on market incentives and some investments are made for reasons of reliability.

Session Two. Efficient Withholding: Why, When and How to Support Efficient Electricity Markets

Electricity load pockets with shortages and inadequate generation incentives; congested transmission corridors with suppliers but no buyers; plant closures with regulatory intervention to find new capacity – what is wrong with this picture? Electricity markets were intended to provide incentives for efficient entry and exit. This dynamic is the key to the long-term benefits of electricity restructuring. The anomalies point to a central problem in market design. The diagnosis involves market power mitigation rules, scarcity pricing and efficient withholding. If investments are lumpy, as often argued with transmission, then ex post market prices could be too low to support efficient investment. If competitive demand bids do not set *market-clearing prices, market power mitigation rules may produce prices that are too low. But if there were excess capacity, an efficient response would be to close plants in the ultimate in physical withholding. Why might practical or complete withholding be appropriate? When is economic or physical withholding appropriate? Should market power mitigation rules accommodate some withholding? How should the rules be modified? What are the appropriate criteria and how can we frame the analysis?*

Speaker One

The fundamental issue is whether we see irrational market outcomes and what to do about them. For example, load pockets with shortages suggest there is something wrong with the pricing in those pockets. If we see plant closures at the same time that we see regulators intervening to create more generation, obviously there is an issue with market signals. Of course, it is possible to have plant closures or potential retirements in areas where there is a sub-area reliability issue. Is there inadequate incentive for transmission investment? Is there excessive market power mitigation?

The real issue in my mind is market design. I think it has become clear that the value of capacity does vary by location. We have addressed local market power mitigation. We have narrowly defined capacity payments, but as a broader matter, the actual effect of transmission constraints on a system does in fact mean that capacity has more value for reliability in one area than in another.

We do have market cycles in this industry. We are in a down cycle at the moment. In PJM, for example, there has been a significant decline in net revenues or profitability of generators. New CT's cannot even come close to covering their expected returns based on prices over the last few years. Correspondingly, there is a reduction in the amount of capacity being built.

That raises the question of the role of energy prices in reliability, whether the natural cycles in the energy market imply both acceptable and unacceptable levels of volatility and ultimately, unacceptable levels of volatility in reliability. It would be extremely volatile to maintain reliability standards solely using an energy market, given that markets are not planning devices. This extends even to capacity markets because investors react with a lag to market signals. What are the optimal levels of volatility on the energy side and on energy and capacity markets that are consistent with maintaining a reliable level of capacity?

One solution is efficient market design, but permitting the selective exercise of market power through withholding is not appropriate. I use the term withholding to refer to the situation where it is not efficient. My definition of efficient retirement is when you spend more to maintain a unit in operation than you take in from it. The relationship between a unit-specific decision and the portfolio effects is important. To pass the test of being an efficient retirement, it has to make sense on a stand-alone basis – that is, not designed to raise the price for the balance of the portfolio, even though it may not make sense on a stand-alone basis.

On the other hand, withholding is done for the purposes of exercising market power. It is designed to increase prices above the competitive level, which means the price that exists when the market design is right and when units are being paid for the services they are providing.

There will always be units that have to retire for reasons of physical failure or other things and it will not be simple to address these matters. Nonetheless, the purpose of having an explicit policy on retirements is to maintain system reliability. Such a policy must be a clear ex ante policy and everyone must understand that reliability is a part of what is being bought and sold when you own a generating unit. Notice provisions of 6-12 months, reliability tests and compensation rules – no unit should be required to run at a loss -- are components of this policy. There should be a market power test: if a unit that is making money decides to retire, particularly if there is a related portfolio effect, that is a strong indication of a market power issue. Another potential means of exercising market power is to retire a unit or part of it but maintain your injection rights – which are property rights.

Question: If a unit recovers its cost of service through what it is charging or loses if it does not is this a cost-of-service benchmark?

Response: The right test is whether or not a unit makes a rational decision to withdraw. Is it an efficient or a non-efficient withholding? You can say the right test is a cash-flow test. Is it more advantageous as a rational business entity to maintain the unit in service than to close it down?

Question: What happens when a company wants to shut down a plant but rebuild on the same site?

Response: It is not withdrawing from the market when you can replace an old, inefficient unit with a new one.

Question: What happens when your state's environmental commissioners tell you to do an environmental upgrade and it costs a lot of money?

Response: An owner should not be required to make an uneconomic investment in upgrading its unit. If it is no longer a cost basis and the owner does not think it can recover the expected required return that is a rational reason to retire a unit. I expect this to happen more frequently with the increase in environmental requirements. From the environmental and regulatory sides, states have a role in the decision-making, and from the economic side, it would be FERC.

Question: If a generator does not run, does it impart any costs on the other market participants in terms of FTR value or allocation or movements in market price?

Response: The question is whether the withdrawal would have an anti-competitive effect: that is, would it effectively result in the price being raised above the competitive price? I think we have to recognize that retirements and mothballing can, in theory, be used to physically withhold and everyone must understand the rules.

Speaker Two

New England has been experimenting with PUSH bidding, or more accurately, PUSH offers. Basically, it is a relaxation of the market power mitigation rules that apply to a generating unit in a load pocket – you will not be mitigated unless you offer above your variable cost plus your levelized fixed cost.

It really means that the cost of the plants when they were spun off by the utilities is on the books. The return of and return on investment varies by plant, but is explicitly allowed within the marginal cost or the short-run energy market offer that you make in New England at this time. It is intended as a stopgap measure until LICAP or another resource adequacy plan is in place. FERC recognizes that the New England markets do not adequately reward or signal the need for new capacity in constrained areas. By allowing existing units to offer at higher levels and be compensated at those levels, some of the ongoing revenue shortfall and revenue adequacy issues would be resolved. It is intended to produce signals for new investment through higher LMPs in the constrained areas.

FERC issued its “Devon order” in 2003 in response to NRG’s filing of request for RMR contracts in New England. FERC’s response was that it would rather have costs recovered through the marketplace and the ISO would implement PUSH offers that would apply to the designated congestion areas. Eligible units were those with an annual capacity factor of 10 percent or less in 2002. The intent was to capture the peaking units that run 2 percent of the year and lack adequate opportunity to recover their costs.

The capacity factors of the PUSH units fell a modest amount in 2000-2002 but plummeted in 2003, the first summer of PUSH unit operation, when the units were allowed to raise their offers and were dispatched far less, because the system found substitutes for their energy.

I compared PUSH with a control group of units in designated congestion areas (DCA). For every single capacity factor tranche, the capacity factors for UPSH units either rose less than the comparable units or fell by a greater amount. To me this says that once you have roughly normalized for the weather in the summer of 2003 and the capacity additions system-wide, the PUSH offers really did work to reduce the capacity factors of the PUSH units.

FERC intended that the units set relatively high LMPs in these locations and to incent investment. In the two DCAs in Connecticut and Boston, there was at last one PUSH unit running two-thirds of the time. They set LMPs between 2-3 percent of the time, depending on the denominator. Basically, these units ran nearly all the time and hardly ever set price. The units did recover because they were paid through operating reserves. There was a clear increase in operating reserve costs. However, they only recovered about 35 percent of their allowed fixed costs. For the majority of the units, the PUSH rules did not even pay them enough to keep them around for an additional year.

The fixed cost estimates were relatively conservative because it was assumed that every hour the units ran, they offered at exactly their PUSH levels. In reality, on average, they offered slightly under at roughly 90-95 percent. Only one of the units that ran all summer was infra marginal at a level at or above its authorized PUSH level. The units did not gain large quantities of revenue from infra-marginal operation when someone more expensive set the price.

Out of 45 PUSH-eligible units, 35 sought PUSH treatment. If the fixed costs over the 2002 run-hours were levelized, 8 units would have had PUSH offers above the prevailing offer cap of $1,000.

In summary, New England’s experience with the relaxed bid mitigation methodology that some people advocate to solve the revenue recovery problem for units that are needed for reliability but are not recovering their costs did not work well. Literally, 2 or 3 minutes came within 80 or 85 percent of covering their allowed fixed costs. That tells me that the real problem with cost recovery is incomplete market design. LICAP is a better long-term solution, we think – or at least until we implement it.

Question: What were the energy substitutes?

Response: Peakers ran more, including non-PUSH peakers. Some units with contractual obligations that saw no benefit to PUSH treatment ran more. There were some increases in imports and some new capacity.

Question: If the PUSH units did not have to push up to the limit, that was their choice. Did they make mistakes or was this the profit-maximizing solution?

Response: We assumed they were maximizing their profits. Occasionally, in our estimation, there were units with marginal costs well below the prevailing LMP in a region that persisted in offering at their PUSH level and did not sell schedule to get online. We also saw people who realized they could profit by scheduling when they saw high LMP. When they did, LMP dropped and then they came offline. The markets are small enough in these sub-regions that one unit in a given hour might have a big effect on LMP, so it is difficult to separate PUSH units when trying to predict accurately when they could run profitably, versus recognizing that if they ran, the units would lower the price to an unprofitable level for them.

Speaker Three

In the UK, there are two approaches that generators can take to do nasty things. One, if you withhold plant, the margin of spare capacity will go down and the capacity payment will go up. That was noticed in late summer 1991 when PowerGen discovered that if it said that some of its plant was unavailable on the day ahead, a high price was set. Two, if the regulators are keen to compare your price offer with your own costs, make sure that a low-cost plant is unavailable for a while. Therefore, a different plant with higher costs will set the price. Although your costs go up a little, your revenues will go up even more.

The UK also faced the problem of what to do with plant in load pockets. The UK regulator conceded that a plant that bid a price equal to its marginal cost plus an allocation of fixed costs was legitimate. It is difficult to avoid the conclusion that PowerGen took the opportunity to withdraw its plant on exceptionally profitable terms

A mechanism that is similar to New England's PUSH mechanism is that plants were informally allowed to bid high prices. Soon, the grid company began having annual contracts with plants in load pockets to ensure a reasonable recovery for the plants and less excessive prices for the grid.

To determine if this behavior is competitive or not, you must ask how much they were making and look at average monthly payments in the pool over time. Depending on the kind of plant, it gives you a wide range of what might be acceptable. Capacity payments also depend on weather, availability and outages. The general conclusion is that with so much variation, it is difficult to be sure that anything naughty was actually happening.

Data for three years when there was still a vertically integrated, state-owned system; data for ten years when fuel prices were stable; and data from one year when fuel prices moved all over the place show that in practice, generators were getting a better match of generation to demand after privatization. That is not to say that small-scale withholding did not occur. From time to time, people probably did delay returning a plant to service for a day or two just to receive a bit more revenue. But they do not seem to have been able to do anything that transferred really large amounts of money into their own coffers.

When PowerGen kept capacity off the market in a very blatant way in 1991, the regulator added Condition 9A to the regulatory licenses of all generators. Generators had to inform the regulator about their policy on availability; produce a forecast of that availability from each power station on an annual basis; and reconcile it with what actually happened. Generators also had to give six months' notice if they planned to close a plant.

Some very large sales of plants in 1999 and further entry has meant that generation to day is very fragmented and everyone seems to think that at the moment it is competitive. Certainly, prices are very low. The condition that governs reporting to the regulator about capacity remains in the licenses and could be triggered again, but it is no longer active.

You could say that the UK regulator applied pressure rather than control, trying to influence the companies, but probably failed to influence the style of plant closures because companies were able to close part of a plant at once and were able to get away with closures at short notice. It may be that some of the evidence that came out of the information provided with Condition 9A set the scene for the divestitures in 1999 that later led to a fully competitive market.

Question: How are capacity payments fixed?

Response: It was the calculated loss of load probability that most of the time is zero and peaks at about 0.2-0.3 because it is calculated day ahead, multiplied by the value of lost load that was set at 2,000 pounds a megawatt hour in 1990 and operated with inflation every year until 2001 when it ceased to exist.

Question: What is the percentage of generation controlled by the largest owners?

Response: British Energy has about 20 percent that is all base-load. PowerGen has about 11-13 percent.

Speaker Four

Culturally, we accept some externalities for competition: business dealing, creative destruction and even to some extent eminent domain. We find others unacceptable such as excessive market power. We tend to dislike dirty water and air and we have problems with uncompensated loop flow. We all know that electric markets have externalities everywhere you look. In particular, since demand cannot respond fast enough to certain events, we have to create reliability through extra generation and reserves.

FERC's core mission is to ensure that there is no discrimination and that the rates are just and reasonable. At the same time we have to prevent monopoly rents – something that antitrust laws do not deal with very well.

In almost all of today's ISO markets FERC tries to create compensatory rights. It is beginning to introduce good scarcity pricing by making sure that the price goes up when generation capacity runs out. From time to time, lumpiness and flaws in market design require that FERC go out of the market to make decisions and to force people to run, and the result is RMR contracts. Most of the ISO test for anti-competitive bidding before they run the market, but not all have scarcity pricing. Contrary to conventional wisdom, this allows sculpted supply offers but it also helps to explain that the resulting prices are just in reasonable in many cases. Although it will not eliminate ex post mitigation, it can lower it significantly.

Another approach is to generate scarcity prices through a demand curve for reserves. A problem, though, is that when we announce that the correct reliability margin for operation reserves is, say, 12 percent – not 12.1 or 11.9 – there may be some more reliability at 12.1. The same holds true for transmission constraints when we treat a nominal level as a solemn number, knowing that we could run above that for certain periods and even to some extent create wear and tear.

We are still debating whether transmission is a public or private good. The answer is neither – or it is a strange hybrid. We can probably get better performance out of the grid with independent transmission that can bid its transmission into the market in a dispatchable way. Problems with transmission rights manifest themselves when we try to do initial transmission allocation in systems without LMP and without transmission rights. We quickly find that the old rights are option rights with more granularity. So asking someone who had 100 MW of firm option rights to take 70 MW of firm obligation rights for the good of the cause is met with some degree of resistance.

No one offers transmission liability insurance because everyone pays for the consequences of a problem. We have not really talked about offering incentives to keep a line running, or about reliability and liability standards.

For me, the issue is reliable market design instead of SMD. We now need to pay attention to reserve pricing and other computational issues and the software is being developed rapidly to do this.

Discussion

Question: I think we have really been talking about regulating the ability to exit the market, rather than entry. Because we are affecting the amount of supply, we are setting the market-clearing price for electricity. How is this form of regulation different from cost-of-service?

Response: In the broader context of getting the market design right, we are attempting to prevent the exercise of market power in a very narrow set of circumstances. Part of the reason we see some retirements is that the markets are incomplete.

Response: The market is regulated. We abide by a set of rules. Once you abide by them, you will make money if you are an efficient operator in the market.

Response: There may be plants in a load pocket where someone is setting a price, but for the 90 percent that are not in that pocket, you are not setting the price. Even if 10 percent is something close to regulation, it may be better than 100 percent.

Comment: Exempting new investment from market power mitigation except in rare circumstances, while controversial, does provide a regulatory exit strategy. Slowly as there is more entry, smaller and smaller parts of the market are subject to regulation.

Question: What defines the base case issue where you are compensated on a cost-of-service basis? I could see an inexorable desire to push ratings down to be able to bid the excess in the market.

Response: Once you allow people to start bidding they will try to de-rate the capacity of their units. You have to know the variable costs and capacity of the units to mitigate. I think there must be an ISO with the technical competence to make judgments about the capacity of transmission elements and where they are.

Question: California's regulators have conducted a thousand impromptu inspections and apparently have not produced any evidence of physical withholding. Have you seen substantial evidence that would warrant the preoccupation with this subject, either in past events or in designing future markets?

Response: While it cannot be ruled out, we have not seen widespread evidence in our region. I note that every engineer I have talked to has ratified the idea that it would be hard to detect.

Response: Personally, I do not like to distinguish physical from economic withholding. I do not go looking for pure physical withholding; I just go looking for withholding. Have I seen massive amounts of it? No, but you do not need massive amounts and you do not need it to recur over and over again. You can take turns.

Comment: You can look for a statistical pattern that is easier to identify if you can gain access to the data.

Comment: To move forward we have to have responsible people making the point that this issue is not quite as big as people make it out to be.

Question: If companies are not bidding at marginal cost, why are they pilloried as trying to exercise market power?

Response: If you bid above your marginal cost, and that includes marginal opportunity costs, you are trying to exercise market power, if there is appropriate demand side bidding.

Question: People argue that the cost of mitigating will be so high that it will outweigh the benefits of what we are trying to do. How much effort and how many people are necessary to adequately monitor a well-designed, competitive LMP market?

Response: I think it makes sense to do a cost-benefit analysis. We expect to have 18 people by the end of 2004.

Response: People do more than mitigate the market. They also gather and analyze market data and provide feedback to the ISO on what they see and what is not working correctly.

Comment: The threat of mitigation has value, not just mitigation itself.

Comment: The best mitigation is one that is failsafe. If people behave competitively, mitigation does not trigger, or does not have any effect on, the market. From an economic view, if the costs outweigh the benefits, you do not do it, but that must be seasoned with political issues. The calculation that is not in your cost figure is that each state commission was mitigating the market when it did cost-of-service regulation and the regional market monitoring units are replacing any number of states.

Question: Can you distinguish between scarcity pricing as one entity's market power or another's exercise of market power?

Response: In competitive markets, you should be bidding marginal cost and should be clearing the market, but from time to time, the demand side will be where you clear and it will be significantly above the marginal cost of the highest generator. Unfortunately, we do not always have that in electricity markets. To resolve the problem, put in a demand curve for reserves that is a public good. When you start shorting reserves, make sure the price goes up to reflect that and maybe even before that, make sure people see price signals. Often in these markets, the price drops when we are short of reserves because we call in many out-of-market units.

Response: New England has instituted shortage pricing so when it falls short of its reserve requirement and meets certain criteria, the price goes to the offer cap. In those limited circumstances, you really mimic the demand side of the market because you are willing to pay $1,000 to refill your reserves. That is not an unreasonable thing to do, given the lack of demand side development in these markets.

Response: The two ways to do it are to rely on the bids of participants or to mandate it by rule.

Comment: When reserves are getting short, operators work to reduce the price during these times even though they do not fully restore the reserve requirements. In the absence of a better way to price those actions, shortage pricing is a fallback.

Comment: Reliability tests are really modeling exercises. What is essential to one particular analyst or area may not be essential to another. We need an analytical framework to make greater sense of the differing conditions.

Response: The essential lesson is that if a market is not pricing reliability the same way that planners are determining reliability, there is something missing from the market design.

Question: If a plant is clearly proven to be uneconomic, and there are economic alternatives, who makes the decision to retire it?

Response: Vast regions in the US have no markets that have monopoly procurement processes that allow, for example, an old steam gas plant that on average uses a third more natural gas than a modern combined cycle, to run against that combined cycle plant if that owner is able to pass the totality of its fuel costs on to the customers.

Comment: A peculiarity of regulation is having plants that are not being used and useful and therefore cannot collect their capital costs in the rate base.

Response: You should be able to make the argument that if you bought a plant when it was a prudent decision and it was used and useful, you should now substitute that plant out and arguably, receive the capital recovery, if there is any, and everyone is better off by running the new, efficient generator.

Comment: It does not sound right that the thirty-five plants in New England required for local reliability purposes, but that cannot cover their costs under PUSH, lacked a plan to cover their costs going forward. The New England ISO would not let them shut down, nor give them RMR contracts.

Response: The LICAP order arose because a generation owner in Connecticut filed for an RMR contract with FERC and FERC told it to take PUSH. Subsequently, the state made a deal with a large generator to enter into RMR contracts with much of that capacity. That is how a particular subset of units will make it through the next year and a half. FERC acknowledges that the additional RMR contracts may be needed in the interim, but they expire when LICAP comes in. This says to me that the ISO's job is to get a complete set of markets as soon as possible. The ISO focused on LICAP but that is now delayed. Until you start reflecting the cost of running the reserve units in a market price, you will not get the new investment to solve the problems that cost you so much money.

Question: Can you do equipment ratings for emergency, short-term and long-term, for economic reasons?

Response: The idea behind ratings is also what the effects are over a long period. If you want to do it for economic purposes, you take away the ability to do it for real emergency purposes when you may need that.

Comment: I understand that the focus on withholding or monitoring can perhaps be a distraction or a dissipation of resources. Politically, though, it is valuable to be able to say that you are monitoring something and to run through the list of potential abuses so that you can inform a customer about some real things it can do and behind that, the prices are what they are. For example, two LDCs are structured differently, and both face tremendous price volatility. The customers of one have confidence, but the customers of the other have virtually no confidence.

Question: Would there be a greater incentive for demand response if prices during the infrequent scarcity hours were allowed to go above $1,000? In markets that have mandatory reserve adequacy requirements, is it more efficient to recover the capacity payment from load in the few scarcity hours, rather than spreading it over a year?

Response: In the UK, large customers pay about $10,000 per MWh three times a year. They do not know exactly when that will be. Many try to reduce load when they think the peak transmission charges will be coming. That could also happen for generation. Again in the UK, you can also sign up with the grid company for a contract that will reduce your demand – with a price attached – when the grid company phones up. In a way, that is also part of a demand curve.

Session Three. Re-Verticalizing Electricity: Is It the Result of the Market or Manipulation? Is It Good Policy? Who Decides?

Recent developments in several states amount to vertical re-integration of utilities, either virtual or real. Utilities applying to rate base an affiliated IPP; an IPP winning a "competitive" solicitation for new capacity by an affiliated utility; and transmission congestion suddenly relieved when the transmission-owning utility acquired the IPP hurt by the congestion have been cited as examples Critics see a threat to competition in bulk power markets, abuses of market power, biases built into supposedly transparent bidding processes, and socialization of market risks that w ill hurt consumers. Others see enhanced reliability, protection of native loads and increasing the resource options. There may be harm if these deals are done with the blessing of state regulatory agencies that look out for the interests of consumers. There may be competitive and regional impacts, despite state regulatory seals of approval. Is vertical re-integration a trend or isolated cases? Who is correct: those who see a real threat to competition or those who see more benefits than harm? Who decides: state regulators protecting their consumer interests, or FERC guarding competitiveness in the larger market?

Speaker One

We are a privately held global developer, owner and operator with 20 facilities either operating or under construction in 10 countries and representing about 16,000 MW. We do not acquire old facilities – we only have new ones. From our perspective, we believe FERC is doing its best to push for a truly competitive market and we support that.

Re-verticalization is more of a regional issue. We have seen cases that more closely represent manipulation rather than being drive by market forces. The problematic ones are those where utilities that have chosen not to open their markets to competition and thereby limit transmission and market access then enhance their market power by acquiring distressed assets.

Today there are thousands of megawatts of new, reliable clean, efficient power standing idle in the service territories of vertically integrated utilities that profess they will open their markets by joining

RTOs. Yet at the same time, some of these same entities stymie the work to get RTOs off the ground.

Often I hear that the IPPS built their facilities in the wrong place and that they are looking for a subsidy or a consumer bailout for their bad investment decisions. Any IPPs has to live with any poor investment choice; some of the choices may have been because of poor location or other factors. Ironically, some utilities collect millions of dollars through fuel adjustment clauses – a situation that I think enables them to continue to run some old, inefficient and dirty generation that perhaps should be retired.

Fuel adjustment clauses made sense during the period of fuel oil price increases in the 1970s and I think they were a good process when regulated utilities and a fully regulated market existed. But today is a different story. I think you could even say that the fuel adjustment clause has become somewhat of a stealth rate increase to consumers and I certainly see it as an impediment to competition. Absent some of the prohibitive regulation, there is no question that IPP plants would have a competitive edge over some of the old boilers.

I also hear complaints that the power from IPPs cannot be deployed for reliability and transmission constraint reasons. I think you would be hard-pressed to find any objective engineers who would say that a new state-of-the-art-plant was less reliable than a 30-60-year-old facility. I think that much of the transmission constraint could be eased to some of the existing modern facilities if in fact we did retire some of the older facilities.

IPPs offer significant environmental benefits. Using some of the latest US EPA and EIA emissions and generation data published in 2003, we compared emissions from a facility we own with the fleet of assets operated by a utility nearby. The differences were dramatic. I admit that the IPP industry has done a poor job of making the environmental case. I hope that policy-makers and others, including IPPs, can do more to consider and define the total economic impacts of re-verticalization. I think the environmental angle will probably be as important as the direct cost to consumers.

Specifically, states should look more aggressively at their fuel adjustment clauses and calculate the most efficient generation, given today's high gas prices. I hope that FERC continues its pragmatic path forward. Absent an immediate adoption of SMD, FERC could help utilities be flexible in how to open the markets and attain the right level of competition. This could mean building out transmission to reduce constraints and enhance reliability; auctioning off some load; economic dispatch, among other items. I admit that the details are extremely complex.

Question: Are most fuel adjustment clauses based on the amount of fuel purchased and its actual cost, rather than the fuel price only?

Response: My understanding is that it is a backward-looking adjustment: what did you actually burn, what did it actually cost?

Question: Is the clause itself inherently anti-competitive or is it not being applied rigorously enough?

Response: I do not think it is inherently anti-competitive. Ultimately, maybe it is unneeded when there is a direct pass-through of how cheaply you can sell your power. My concern is its potential to mask real competition if it allows utilities to run less-efficient plants but not be hurt economically because they can pass on the increased cost of their inefficient use of the gas.

Question: Is your definition of economic dispatch the dispatch that is based on short-term marginal cost or variable cost?

Response: Economic dispatch is complex because of the many system requirements and other factors that must be balanced, but I think that some of these can be easy to hide behind.

Speaker Two

I have spent most of the past decade working on the problems of electricity risk management. Power procurement for incumbent utilities has featured prominently among the issues, as has the analysis of POLR and similar services. I believe that re-verticalization is potentially a problem, but I do not yet know how large. Most important is the implication for wholesale market development because of the lack of confidence in wholesale power markets is holding back other aspects of restructuring. So anything we can do to promote the evolution of these markets is good and anything that appears to impede them is a bad thing. To identify possible solutions we need to understand why utilities, regulators and other participants are inclined to pursue re-verticalization.

The key features of the conventional electric utility business model of a decade ago were: exclusive service franchises; cost-based ratemaking, rate-of-return regulation, fuel adjustment and purchase power clauses and access to regulators to seek relief. Risk management was built into the traditional public utility structure, an attractive feature for both managing and regulating the system.

In today's environment, in addition to the conventional load forecasting problems that always exist, utilities now contend with the possibility that their customers may switch. On the demand side, the risk is both greater and asymmetrical because if customers have in effect been given switching rights, they are going to take advantage of that opportunity. In New England, Pennsylvania and other places with an option to buy at the lower of cost or market, we saw customers switch and switch again. To some extent, this problem has been addressed by a more careful design of POLR, but it is still an issue.

On the supply side, having sold off their generation, utilities now find themselves buying power to fulfill their retail service obligations. Today's power markets are extremely volatile, meaning that prices can move a lot in a short time. If you have uncovered positions, you have a lot of risk exposure that could be very costly.

The trading and marketing firms today not only mange price and credit risks – the conventional focus of risk management – they also deal with load risk. For example, if a utility bought forward to cover its forecast load positions, potentially there is very substantial residual risk because loads are uncertain and you can still get hit with a nasty unanticipated purchase power cost. In addition, a utility that does not own generation has a wide array of potential power purchase programs available, so in theory, it could cover its obligations in the spot market. But I think it is obvious that is not a good idea. If it decides to buy forward, the utility must determine how much exposure it should cover; when it should buy forward and if it should buy options or more complex instruments. And there is no book to teach you how to hedge.

Regulators have not been good about specifying what utilities should do. Utilities have been left hanging. For example, the Nevada power company got hit with a bill in the hundreds of millions of dollars because it was found to have been imprudent in its power procurement program. Even if regulators try to abide by the principle that you evaluate decisions based on the information available at the time, as a practical matter, that can be a difficult principle to put into practice and is a nasty regulatory risk management problem for these utilities.

The motivation for vertical re-integration is as a risk management strategy for electric utilities that are feeling pressed both by regulatory risks and long-term market reliability risks. We need to find ways to make managers of incumbent electric utilities feel more comfortable about relying on wholesale power markets.

New Jersey is a good example of a jurisdiction with a standardized, coordinated statewide procurement process that largely resolves the regulatory risk problem. However, the entire state resides within one market area. By contrast, parts of Illinois are in two or no control areas. Requiring competitive, standardized procurement processes is important.

Also important as a practical matter is the recognition that special circumstances may warrant allowing utilities to acquire generation assets. But we should establish a high bar for those exceptions.

Again, I think the single biggest source of motivation for vertical re-integration is the lack of confidence that wholesale power markets will deliver the kind of reliability that incumbent electric utilities are required to provide.

Question: Do utilities take into account the risk that the generation they purchase or build today might be obsolete technology later, when it is still in rate base?

Response: The industry probably does not pay enough attention to long-term technical risk from an investment perspective.

Question: How do you rank switching compared to all of the other risks associated with POLR?

Response: I think several utilities and regulators have redesigned POLR structures to mitigate the switching risk, but I still think it is an issue.

Question: Do you distinguish ownership from long-term contracting?

Response: Having a 25-year power purchase agreement is a lot like owning the underlying physical asset.

Speaker Three

Much of the process of vertical de-integration of the electric industry was based on very broad assumptions about very big, theoretical ideas. When looking at whether things should be efficiently vertically integrated, we weigh the benefits versus the costs. Much of the model for vertically decoupling the electric industry came from looking at the gas industry. Assuming there is a strong potential for a competitive wholesale market, the integration of a strong monopoly transmission may mess up the development of that market. When we were worried about taking wires away from generators, we ended up decoupling supply from the responsibility to provide load – the obligations to customers. And you do not necessarily fix that problem efficiently by reintegration.

Have the people who want to have vertical re-integration given up on the wholesale market, or have they given up on retail? By retail market I mean the assumption at the state level that LSEs would arrive and that consumers would have a choice. Anyone who manufactures a product takes supply risk, because people switch all the time. If you think that the characteristics of the market are such that you cannot mitigate the risk involved in having an adequate supply for your customers, you are really saying there is a market failure at that level and maybe you will return to the old style – the local, regulated distribution monopolist that sells to households.

If you have given up on the wholesale market and you do not trust that any of your supply will be at a good price or will be reliable, the only way to hedge is to vertically integrate, either by contract or by having a much larger percentage of a plant owned by the local utility. Now you are back to the days of integrated resource planning, which was just another way for the regulator to agree to your portfolio ahead of time and if you made a wrong decision, it was the regulator's fault and ratepayers paid for the mistake. All these regulatory solutions do not get rid of market risk: they just determine who will pay for it and who makes the decisions to manage that risk.

Regulators have two good incentives that lead them to bad reasons to have vertical integration. The first is consumer protection. Opening retail markets does not change the consumer protection problem, but it does make it more complicated for regulators because there are many companies to police. There will never be bargaining equity between the consumer and the electricity provider. Perhaps regulators will need to create licensing provisions, or minimum levels of supply requirements for LSEs.

The second is risk management. Everyone in a competitive market must manage risk. Deciding to vertically re-integrate to get rid of these risks is like saying that you do not know what you will be doing tomorrow, but the only way you can be certain of the outcome is to kill yourself today. I point out that unless you know that the market is dead, vertical re-integration is not the best first choice.

Question: In a vertically integrated model, could distribution companies also hedge by going to a third party?

Response: If you believe that the wholesale market cannot function, the benefit of going to a third party is non-existent.

Question: Do you distinguish between the retail mass market and large C&I customers?

Response: Yes, because when you analyze whether it is efficient to provide demand responsiveness and other contract services, the disparities are important.

Speaker Four

California is once again on the leading edge of some of the big questions of the day. The views differ on whether there is a move toward re-verticalization; whether deregulation is dead; and if reliability is the new buzzword. I would posit that we are all operating in a narrow band of hybrid market structures, and that any movement is not going to lead toward anything resembling full re-verticalization, just as the march to deregulation did not produce complete desegregation in most markets. I would also posit that the many states that only took half measures toward the new market structure are in themselves one of the biggest reasons that the structure failed to produce the intended results.

Today, California has an ISO to manage transmission; IOUs that divested a good portion of their generation; a PUC and legislature that are divided on how to go forward; and a new governor who is committed to a core/non-core hybrid market structure with a competitive wholesale market. The debate now is about the rules and as we all know, the rules will define the market.

In defining these rules, regulators must understand the purpose of developing a competitive wholesale market in the first place. The reason of course, is to reduce the wholesale cost because it is the largest component of electricity's retail price. This has been the Holy Grail of regulators with every new wave of reform, yet in California, every new effort to reduce prices only caused them to go up, leaving the state with billions of dollars of stranded costs that have taken years and sometimes decades, to eliminate.

Note also that if the goal is to lower wholesale costs, to the extent you become too creative by focusing on community aggregation, green power, or municipalization, for example, you diffuse your ability to achieve the goal. Planning for procurement becomes more hazardous and there is greater potential for stranded costs and cost shifting.

Regulators must also recognize that the process itself only adds to inefficiency. The more rules and regulations placed on the procurement process in the interest of protecting consumers, the harder it is to achieve the efficiencies that lead to lower costs. This is a political issue because the lack of efficiencies that competitive markets produce is used as a weapon against competition. It involves an understanding of the competitive process and a lot of trust. We have to trust the market, trust FERC and trust in the rules that we put in place. Regulators do not trust – regulators regulate.

The regulatory costs of hybrid markets can be expensive. Monitoring between regulated and unregulated activities; ensuring ratepayers get what they pay for; coordinating design and delivery in a competitive market; preventing cross-subsidization; inconsistencies in prudence reviews – all can easily offset the cost savings associated with choosing competition over vertical integration.

From the regulator's view, such costs will make it easier to choose the path toward vertical re-integration.

And I believe that figuring out how to level the playing field for procurement will become the central focus. The relative success reached will determine the ability of third parties to compete for investment in states like California, which in turn, will determine the move toward a greater degree of vertical re-integration or competition

Regulators can be fatally myopic as they make decisions daily in a vacuum and find it difficult to see where they are going. Either their decisions fit neatly into a larger process and a larger strategy, or they hinder the effectiveness of that larger strategy. We do not have a clear view right now and so by default, we are going to go towards the path of safety that is vertical re-integration.

Discussion

Question: What is a hybrid market?

Response: In California it means a market where customers at some level, either 500kW and above, can choose in the market place. Core customers, largely residential and small businesses or anyone else who chooses to be in the core market, are served by the utility in a bundled rate structure.

Comment: California's wholesale market experiment seemed to work, although the cost to the consumer went up.

Response: There was a time when the US was just finishing paying off the debt from its nuclear transition and costs had started to come down, but in California they were still higher than in other parts of the country. Generally, the state has not been able to get down to the national average in retail costs.

Comment: I think that some utilities are really interested in vertically reintegrating.

Response: Of course there are utilities that want to be vertically integrated, and utilities that are asking regulators to bring assets back into rate base because of the risk factors.

Comment: We need to emphasize the motivations that come from retail ratemaking. If you are a regulated LSE and you rely on purchase power contracts, you are just trying to avoid losing money. These contracts are essentially debt on your balance sheet. If you bring them into rate base, you have an investment and right now, Wall Street likes rate-based investments, considering them earnings in perpetuity. Given that we never fixed the disconnect between rate base versus purchase power contracts, and given the premium now being placed on regulated earnings versus a discount for market-based earnings, I think that many regulated LSEs believe ownership is the way to go.

Comment: The idea that we should set competition policy based on whether there is a more certain revenue flow from a monopolist versus a market-based company is shortsighted. Yes, the market will tell us to make it as safe as possible and the safest way possible is to make it a monopoly so that all of the price risk is borne by the captive customers.

Question: To what extent are wholesale design issues related to the desire to control the price of electricity in a market that is more volatile than customers expect?

Unlike gas, in electricity the regulatory ability to affect prices is usually 12 months at the earliest. There is an enormous political push to go back to vertical integration that makes it difficult for regulators t0 examine the problem and the solution.

Comment: Separating transmission from the vertically integrated model would probably go farther than almost anything else to ensure a competitive wholesale market.

Response: I think that we are not doing enough to develop the existing grid into a more rational mechanism for providing transportation for new and emerging markets. By having operational separation through RTOS we have not achieved the same results as if we had had actual divestiture and independent transmission companies.

Response: I think it is important to keep transmission and generation together.

Response: I think part of the problem is because people think they are direct substitutes for each other and they are not.

Response: If a utility wants to build a power plant, its offer is not the same thing because it has a transmission problem to get there. We need to solve this problem if we are going to address the conditions under which it is and is not acceptable for utilities to build generation.

Question: Does it make sense for regulators to force businesses to go to an hourly rate – in other words, to shop?

Response: Without forcing customers to install real-time meters, I think you have a greater risk of cost shifting.

Response: When gas prices rose, everyone thought that consumer demand would not change significantly because gas was used for home heating. Instead, people bought new water heaters and insulated them. Why? Because manufacturers had a reason to develop more efficient heaters. Yes, there was some government help, like Energy Star, to push them in that direction. But if you are not going to save money you will not spend the extra $150 to buy an efficient appliance.

Comment: Some of the problems we have are related to whether there is an RTO. In places where there is none, the problems become FERC's.

Question: The majority of states still operate outside an RTO and more importantly, outside of an organized wholesale market, so that the decision of a particular vertically integrated utility to add to its generation portfolio is not only for the purpose of managing it s risk but also adds market power to that particular organization. Should the rules be different for states with and without RTOs?

Response: If you are a regulator in a non-RTO state looking at the existing situation, you may still not want integration to take place by ownership. But if you really want to foster the eventual availability of a competitive wholesale market, you do not want to make that impossible by completely vertically re-integrating, because when your state must weigh the costs and benefits of encouraging an RTO, it will see only the costs. Regulators do need to look at whether their decision would eliminate the possibility of establishing an efficient RTO.

Response: Regulators also have the opportunity to examine whether their decision changes transparency because if they make the market thinner by putting assets back into rate base, it will be more difficult for them to examine and benchmark transfer costs.

Comment: Regulators have to worry about the variable cost issue and the capital costs for economic dispatch. As an alternative to fuel adjustment clauses, perhaps there could be an incentive regulation that only a certain percentage of fuel costs can be passed through, and the remainder is borne by the shareholders.

Question: In the future, will IPPs be unable to obtain permits to pollute? That could be a market barrier to entry.

Response: I do not see it as a barrier, but as something that works with the market to change the cost profile to some degree, and that will initiate new research and investment to find even lower emissions.

Question: Are we really talking about a procurement issue, rather than vertical re-integration?

Response: If there is a well-functioning wholesale market, you should have a portfolio of contracts for different lengths of time. The villains are the investment bankers who are unwilling to look at someone who wants to build a plant unless they walk in the door with a 20-year contract and take all of the market risk.

Comment: Merchant plants could be financed and built if there was a functioning competitive market and companies had confidence in the regulations.

Comment: I agree that this is a procurement question but there are nuances that have do with the structure. For example, in California there have been some academic questions about whether to develop a capacity market. That is a procurement question, but it also changes the dynamic in terms of the players and the financing.

Response: Vertical integration hides mistakes for regulators and for utilities. Some of the biggest problems in creating competitive markets are that people can make mistakes. If we do not have price transparency, we cannot see the havoc that is wreaked by our present demand and congestion issues. Politicians are comfortable when you cannot see. They do not want people in Boston, where there are a lot of voters, to see that it actually costs more to supply electricity here than in Maine where there are not so many voters. They want average cost pricing because it is comfortable. We cannot get rid of price volatility unless we get rid of demand inflexibility. We can only get rid of how often we see it and who pays it. In other words, price transparency is not an unequivocal good if it highlights problems that are difficult to solve from a political perspective.

Question: Would an IPP ever be able to be on a level playing field with an affiliate?

Response: We could completely vertically de-integrate the affiliate in a theoretical world.

Comment: A significant driver for utilities is the motivation for putting something in rate base. This suggests that either we need a different method of setting rates or to separate and provide different ratemaking treatments for different functions. I think we must recognize that re-integration implies that there has been some degree of disintegration and that the concept of the core/non-core market is only relevant if you assume that there is a wholesale market that can deliver benefits to the non-core market. Otherwise, why make the separation? Understand that re-integration, or the utility owning the generation is the equivalent of a very long-term contract.

Question: There are four scenarios: an RTO market where policy and economic theory can work and there is less need for a pragmatic response; a lack of generation calls for utilities to build, at least pending the development of the market; a surplus of generation without many transmission issues where, pending an RTO, pragmatic mitigation must deal with the market power issue; and a surplus of generation that lacks the transmission to bring that generation to the load. If California is in the last scenario, are its commissioners willing to and politically capable of taking the pragmatic approach that will get the transmission built quickly?

Response: The CPUC is studying how to alter its process so that it will not second-guess the needs determination made by CAISO. If it cannot do this, the legislature will give the authority to the California Energy Commission.

Comment: It is important to keep in mind how to evaluate the different situations and approaches that companies are taking. Although market power has not necessarily gone away whether or not you are in an RTO, I think it is considerably mitigated. The roles of the states and FERC are not mutually exclusive. The time of counting on that jurisdictional battle to delay change and restructuring has ended. That is not to say there will not be disagreements. There certainly will be, but they are legitimate and respectful ones and I think, generally constructive. In the next short period of time, we need to keep thinking about how to deal with what I think are some short-term but potentially extremely disruptive issues.