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HARVARD ELECTRICITY POLICY GROUP SEMINAR

THE EVOLUTION AND CURRENT STATUS OF COMPETITIVE WHOLESALE POWER MARKETS

Harvard Faculty Club, Cambridge, Massachusetts

September 23, 1994

MEETING SUMMARY

Introduction

Should the major focus of debate over the future of the U.S. electricity industry focus on wholesale or retail competition? Some industry observers have argued that moving toward greater wholesale competition would require addressing most of the salient issues bearing on industry performance. Ina sense, these arguments have come full circle: brought to the fore by recent proposals in several states, the debate over retail competition has hi -blighted that a necessary--but not sufficient--condition for effectively promoting competition generally is to enhance competition within the wholesale market. Additionally, many in this Group have stressed that, in addition to refining our visions of alternative market models for the long run, we ought to focus attention on problems encountered in today's marketplace by its various participants and determine the scope for possible improvements. This theme--better understanding the performance of wholesale markets--has been the impetus for holding this seminar.

Our past discussions have drawn on the experiences in the United Kingdom and other countries, and we will continue to profit from studying them. The morning's speakers offered perspectives on the problems that they see currently existing in U.S. wholesale markets, and outline their recommended policies for reform. This discussion was followed by one which explores recent developments in California.

I Experiences in Evolving Wholesale Markets

We have seen a general consensus emerge that the vertically-integrated monopoly system is "broken, " and needs fixing. Proposals for reform that have been aired include, at one extreme, simply opening up the system completely to induce a dramatic change in the way the industry does business. Others, frequently academics, suggest learning from the experiences and practices of the United Kingdom and other countries. A range of models for dealing with monopoly and enhancing competition are already in place and deserve serious consideration.

<u>First speaker:</u>

I'll start by outlining the underlying principles of our reform proposal:

- There are operating cost savings to be reaped.
- If we accept that stranded assets are covered, there should be some rate reductions.
- The more competition, the better.
- Stranded assets are better handled by embedding these costs in generation contracts than with charges "on the wires."

The average real electricity price in the United States has been declining since the early 1980s. For electricity purchases from independent power producers (IPPS), the decrease has been even more pronounced. In the early 1980s, most contracts with IPPs were in the 4 - 7 cents per kilowatt-hour range. Competition and the entry of new players has pushed this figure down to $2^1/2$ - $3^1/2$ cents per kilowatt-hour today (there is some variation, depending on fuel costs and location). To cut costs, IPPs have increased plant availabilities, cut construction lead times, enhanced competition for various cost components (including capital cost), and made use of innovative technologies, such as fluidized bed combustion for coal, and natural gas combined cycle and gas turbine plants.

The essence of our proposal is to *separate generation from transmission and distribution* to create competition within the generation market. To achieve this separation, we propose that utilities auction off their generating assets. These assets would be coupled with a sales contract that would include an immediate discount for ratepayers. An alternative to the standard auction format would be to set book value as the asset sale price, thus covering costs of stranded assets. Under this option, bids would be taken for the rates to be charged to customers. Clearly, this mechanism offers incentives for cost reduction, including cutting pollution emissions where market-based environmental controls are in effect. Note that the buyer under this model sees a contract price that, at least for a transition period, would be stable. It is this stability that supports the higher book price for the asset. In the absence of such contracts, uncertain market conditions would elicit very low bids for generating assets. Finally, a power pool should be established to provide a spot price, and to provide stability, voltage support, and other engineering functions.

Discussion:

The speaker was asked about the treatment of decommissioning liability for nuclear power plants. Some nuclear plants' variable costs, it was argued, are in excess of the (putative) spot price of electricity, and should therefore be shut down. Society would be better off paying the stranded investment costs associated with these plants in exchange for the utility shutting them down. There is always the possibility, however, that once exposed to a more competitive environment, these plants could reduce their costs.

Second speaker (representative of the independent power industry):

I'd like to provide one perspective from the independent power industry on structural problems existing in today's wholesale power market. My fundamental point is that, despite much movement in the past decade toward a competitive generation market, there remains today a systematic preference for utility construction over non-utility construction. As any independent power producer .(IPP) seeking new markets for existing assets can readily demonstrate, competition is *not* alive and well in most utilities' service territories. Some illustrative examples in support of this claim are:

- The sanctity of contract has been under attack in many states. "Buy-versus-build" competition is frequently tilted in favor of utility construction.
- State regulatory systems designed for integrated utility monopolies have been slow to adapt to the needs of the competitive market.

Despite assertions to the contrary, we do not yet have a competitive market that fosters competitive behavior. The conventional definition of a competitive generation market is: *many buyers and many sellers engaging in arms-length transactions.* While there are many sellers in the wholesale generation market, the retail market continues to be dominated by the monopoly franchise. As long as utilities are represented on both sides of the transaction fence -- as both buyers and sellers -- competition is not feasible. We also do not have many buyers -- in effect, there is only one utility buyer within any utility's service territory. Absent these fundamental conditions, a competitive market cannot flourish. We believe that it is dangerous to predicate further industry reforms on the assumption that the market is competitive, when in fact it is not.

Third speaker (representative of the independent power industry):

In today's generation market, the utility's desire to increase its profit may conflict with decreasing costs for ratepayers. The more a utility invests in its own generation, whether that happens to be the least cost resource choice or not, the greater its rate base and the return on that investment. Laws and regulatory practice have institutionalized this conflict to some extent, but as competitive alternatives increase, we see utilities understandably becoming ever more determined to maintain their financial strength. Our fundamental argument is that the preference for utility construction is embedded in the legal and regulatory foundation of the industry. Until we tackle the admittedly difficult task of identifying and removing these systemic preferences, we will not be able to achieve the benefits of competition in today's electricity industry. These preferences can be categorized as: barriers to entry, pricing, and anti-competitive utility behavior.

Barriers to entry

Utilities retain a substantial advantage in terms of entry into the generation market, in terms of need determination, contract performance, and eminent domain.

Utilities have a great deal of influence over the determination of need for power, including the amount, type and what particular alternative will best meet that need. Where utilities do not make regular need filings before a regulatory body, they may be aware of a future need before other parties, giving them an unfair advantage. Even where regular filings are made, the utility has an advantage as the source of most, if not all, of the relevant information. It is also the first to know of changes in the circumstances. Utilities need this information for many purposes, and it is important that regulators have this information, as well. But this legitimate differential in information becomes an unfair competitive advantage when the utility is occupying the conflicting seats of both *generation competitor* and *system planner.*

Another barrier to entry is eminent domain. The utility has the power to take land and in most cases and an independent does not. This increases certainty of return for utility-planned projects.

A different standard also exists for utilities and independent generation developers with respect to deadlines, milestones, and contract performance. Independents are often required to meet strict project deadlines or post a form of security deposit as insurance. These provisions are a normal part of independent power development and are not inherently unfair. However, utility players in the same process enjoy far more flexibility. If a utility project is delayed, it does not face the same risk of cancellation or replacement by a competitor that an independent project faces. Penalizing lateness or nonperformance is good business practice, and it becomes problematic when such requirements are placed on some competitors and not on others.

Pricing and Cost Recovery

Another source of anti-competitive bias in the existing wholesale power market is pricing policies, including certainty of cost recovery. Barriers to competition also flow from cost differences between the incumbent utilities in the market and new independent entrants. Where a utility is a competitor in the generation market and uses ratepayer-funded resources unavailable to independents, it is enjoying a cost difference attributable to its legal status rather than to its skill as a competitor. This is a defect in a competitive generation market.

The use of ratepayer-funded resources also raises the question of who really owns utility land and power plant sites, who backs the financing, who owns surplus capacity, and who actually funds development costs. Under traditional regulation, it was not necessary to distinguish utility assets from ratepayer assets. Faced with competition, some utilities are seeking a free market for benefits flowing from investments while trying to preserve regulation that exempts utilities from competitive risks. For example, if ratepayers paid for a site, it is not an asset that the utility should be able to use without compensating ratepayers. The fact that the site is available and that it is treated as the *utility's* site, giving it the first chance to use it, confers on utilities an advantage. Any competitor should be able to propose a plan for a particular site, because no generator really owns it; the ratepayers own it.

Another problem with pricing and cost recovery regulation is discrimination in cost-cutting. Respect for the legality of contracts and prudent investment is important, so that the financial community will be willing to provide capital. The focus of regulatory reform ought to be, not on recovery for these former investments, but on cutting costs efficiently. At many utilities, total costs are too high. The costs that should be cut are those that can be cut most efficiently, while respecting legal obligations, both contractual and franchise-related. In some regulatory jurisdictions, the focus has been on renegotiating power purchase contracts rather than looking at the utility's overall economic plan. For utilities to change the way they look at this issue, there needs to be a change in the way they recover costs. Utilities need to know, for instance, that they will not be penalized if they make the decision to close a plant.

Another source of inequality is the way in which utilities are able to use ratepayers to cover their competitive losses, thus insulating their shareholders. Ibis situation dilutes the utility's incentive to choose the least cost resource. Many utilities argue that they have the incentive to choose the best resource because they'll lose load if they don't. But when they lose load under current ratemaking practices, the other ratepayers pick up the costs. Having ratepayers to bear these risks makes it easier for utilities to finance projects than independents.

Another pricing-related issue is the frontloaded recovery of costs, a practice that also works to utilities' competitive advantage. Under rate-based regulation, utilities essentially recover project costs up front. Independents also frontload, but they have to establish an escrow account to do so. As long as escrow payments are based on the difference between a frontloaded and a levelized cost, there is no inherent inequity. Inequity arises, however, when the escrow payment is based, not on the difference between frontloaded and levelized costs, but on the difference between frontloaded costs and the utility's "avoided costs". Utilities don't face this situation. No one demands that a utility's project be required to pay refunds if in, say, year 14 of its life, it turned out that other alternatives would have been cheaper. But that's exactly what is being asked of independents these days. I am sure that utilities would agree that a prudent investment should not be determined with hindsight.

The last point relating to pricing is fairly simple and obvious, but it has important competitive implications. When utilities participate in competitive procurements. they must be held to their bid. Regulators have a legitimate interest in maintaining the financial viability of utilities, but this interest can create a competitive difference between an independent and a utility. Independents have to live with their bid prices, but if a utility wins a bid and finds that its costs are more than it anticipated, it may be allowed to collect that difference.

If it is allowed to collect that difference, or if it anticipates at the bidding stage that it will be allowed to collect that difference, the utility has an unfair competitive advantage.

Anti-competitive utility behavior

It is important to realize that the utilities are simply behaving rationally given the economic incentives that they face. They will continue to behave anti-competitively until fundamental legal, regulatory and structural problems are addressed. These problems can't be wished away by saying "Competition is here". They need to be confronted by policymakers directly.

One important potential area of reform is ensuring equal access to information. Variables such as demand and load can change between the time at which the winning bidder is chosen and the iime a project comes on line. Since the utility is an expert on these factors, it can use its inside information after an independent has been selected in an attempt to reopen a competition and show that the utility's own plant would be a superior choice. A resource acquisition system that allows post-competition design changes: i.e., allows any winning competitor to fine-tune his project, would solve this problem. In some cases, state rules are attempting to provide for this.

Utilities also benefit from special treatment for zone costing. Utilities can allocate costs associated with steam production to electric customers and underprice competitors in the steam market. Similarly, when utilities offer economic development rates and other industrial discounts where the difference is paid for by other ratepayers, they gain an unfair competitive advantage.

Conclusion

In looking forward toward the future of the electricity industry, we cannot assume that the wholesale power market is competitive. Many elements are in place, but many are still developing. If we build market structures based on the premise that competition is here already, they will fail. Two tracks must be pursued simultaneously -- structural change and the definition of a new role for regulators.

Discussion:

Question: What is the source of eminent domain -- is it associated with utility status, or is it conferred by a siting body, in that whoever owns a plant site gets eminent domain? I

Answer: In some states, eminent domain is associated with utility status; in others, state statutes provide fora formal siting process and define criteria for issuance of certificates of public need to establish the power of eminent domain. While considerations of eminent domain are rarely pivotal, this kind of certainty in the context of a bidding process does influence cost estimation.

: It is incorrect to suggest that ratepayers own a portion of utility assets. This position is not reflected in law or regulatory practice. There is case law addressing this question (in, for example, transit cases). The question of who owns the assets of a public utility has been litigated repeatedly in federal courts for years (although not in the Supreme Court), with the result that companies, not ratepayers, were determined to own the assets. (Another participant argued that the pivotal issue was not the ownership of the assets but the disposition of the flow of rents from the assets.)

<u>Fourth speaker (representative of an IPP)</u>

In terms of its location along the time continuum of industry restructuring, the electric industry reached the point *last* year where the natural gas business was in about 1984. In 1984, access was opened to transmission systems, and we saw the development of a whole new range of marketing institutions that were buying and selling natural gas across the grid. This analogy to the gas industry holds up pretty well, because we're now at the point in which the gas business found itself in 1985. We now have in place a number of players who are actively looking to act as buyers and sellers of the commodity of electrons across the system, and we're seeing the development of a wholesale market for electric power.

The analogy continues: In 1984, the gas industry reacted to these new businesses and new activities with little interest. By 1985, however, they were actively hostile to the developments in this new market. We are seeing a similar pattern of reaction among power companies in North America, who are moving from lack of concern to active hostility to the development of the wholesale market. The one thing that has been surprising is the blatant use of market power to try to stop this business from taking off by the existing players in the industry. There seems to be less sensitivity in this industry to anti-competitive practices and antitrust issues than there was in the oil and gas business.

One indicator of where we are in the restructuring process is given by the number of applications for power marketing certificates. The year 1993 saw a sharp increase in the number of applications; those applications are now being approved and the marketers are going into business. The first step in starting a marketing business is negotiating interchange agreements. These agreements draw up the mechanics of the rate sheets for transacting business. Once these rate sheets are agreed upon, filed with FERC and approved, you begin to build your portfolio of supply sources, your sales markets and start putting together transmission access agreements so you can actually do business. It takes. a reasonable period of time to get the business up and running. We are about now to the point that we are able to transact business: as of September, we have 28 power interchange agreements in place; we have joined three power pools; and are moving about 228 megawatts per month, up from zero in June. We have four transmission agreements and tariffs in place. In the process of putting this business together, we have seen a radical change in the attitude of the electric utilities that we're dealing with over the last six months, from an initial willingness to enter into agreements, to active hostility to our efforts and attempts to stop us from transacting business.

A number of key issues regarding market conditions have come up that will become increasingly important as the power marketing business grows. The first one is *access to transmission.* One cannot get access to transmission on a prompt basis at competitive rates anywhere in North America because of unequal access to information. Utilities do not share information that they use themselves, and many of the power pools do not provide information in terms of pricing. Even with pool membership there are certain limitations on the access to information, depending on what your membership status is.

Another issue that is coming up repeatedly are standards for liability. Some performance standards are predicated on a business' status as an electric utility, having in place the asset base that an electric utility has. When formulated, these rules did not contemplate the existence of third party marketers on the system. Things like reserve margins and spinning reserve are stipulated as required, whether or not they have anything to do with a specific transaction. These rules are analogous to telling a guy who's buying porkbellies on the Chicago exchange to go in the backyard and prove he has pigs before he can sell any of those porkbellies to a third party. A number of such standards and restrictions will need to be changed for the market to develop.

We have recently encountered several examples of anti-competitive practices. We've had cases in which buyers and sellers and transmission parties were in agreement, contracts had been executed, and the power pool interceded to stop the transaction because it had our name on it, in spite of the fact that we had a written approval from the power pool and did not need any further approval to continue the transaction.

A number of procedural requirements are just unworkable when you have fifteen-minute dispatch. If you're in the market trying to sell fifteen minute, one-half hour, or one-hour power, it's very difficult to give three months or two months prenotification for a transaction. And, in most cases, while those terms and traditions are not enforced for member utilities, for outsiders they are magically enforced.

Another practice frequently encountered is utilities entering into very long-term discounted contracts with customers in an attempt to hold onto these customers as the markets open up. We had a buy and sell agreement with one utility which was terminated at the last minute. They said, "Yeah, it's a good deal for us, but we already made too much money this year." Another utility asked, "Aren't you finding it rough to get agreements? All my neighbors have agreed to slow-play you." That's illegal. This is a case in which we had a transaction, the power began to flow, and then suddenly we received notification that the transaction had been terminated and got a call from the utility saying, "Well, I took that one away from you, didn't I?" It was a case where we had to file with that utility and telling them who the buyer and seller were; they then went in, discounted their price and took that business away from them. Other things overheard in the process of getting our business going include, "We do buy-resales for other utilities for a buck but with you, it's whatever we can get"; "We will transmit for you or sell for you as long as you are not taking away any of our customers." We also applied for membership in the Southeast Trade Association -we were told that our application was filed in the appropriate place and we've never heard anything back.

We generally saw the same patterns of evolution when the gas business opened up. Nonetheless, the degree of blatancy of these anti-competitive practices in this industry has been remarkable.

Discussion:

Responding to a questioner, the speaker indicated that he viewed it as anti-competitive to enter into long term contracts with customers, even with willing buyers and sellers. He saw it as analogous to special marketing programs in the gas industry which would, in his view, eventually be challenged as discriminatory discounts.

One participant asked if it were possible to establish separate relationships with utilities, on the one hand, and with pools on the other, such that pools would behave neutrally with respect to power marketers. The speaker responded that concurrent interaction with both pools and utilities was necessary to complete transactions. The "Poolco" proposals that envision greater separation between utilities and pools would, however, reduce the difficulties that power marketers face. Today, one must depend on entities that have control of monopoly assets to get access to the grid. They have no incentive to cooperate.

First respondent:

I share the speaker's view that there are close parallels between gas and electricity in terms of industry development. I do think there are some differences, however. There are not as many buyers or sellers in the market as we had in the gas industry. The gas industry had in 1985 and still has today many producers in the marketplace apart from the pipeline, and also many buyers. In contrast, on the electric side, there is a relatively small number of wholesale customers.. Another difference is that we experienced gas shortages in those earlier days, such that pressure for change came from *customers* in a way that has not yet been seen in electricity. Finally, the FERC had the authority to make competition happen in the gas industry; it cannot do so for the electric industry.

Throughout the industry, people are waking up to the reality that it's going to be a more competitive world. I think that Detroit Edison is an excellent example of a company that's locking in customers for the future (by establishing, for instance, special rates for General Motors). Other companies are doing the same thing, and it's not like they're negotiating with a happy customer that doesn't have any power.

With respect to retail wheeling, consider the Michigan experiment, the proposal that Wisconsin is looking at, and Ohio's planned round table on the topic. Both regulators and companies are becoming aware of the changes and moving in the direction of a more open market.

I would disagree with the speaker on one point. I believe that state commissions, in spite of their experience with the natural gas and telecommunications industries, are more interested in protecting their own regulatory authority and control than they are on relying on competitive forces in the electric industry. This is going to result in a Balkanization of the industry and will make it very difficult for power marketers across the country to be able to operate effectively.

Second respondent:

A number of conditions in the marketplace make it difficult for new entrants to do business in many parts of the country. Some parties place a premium on a familiarity with the rules of the road in the evolving market. Players who are experienced in the market know best where transmission constraints are likely to arise and know when transactions are likely to be interrupted if a source is on the wrong side of the transmission constraint. With increasing experience, power marketers will learn the physical rules of the road in their operating areas. Nevertheless, I believe that there is a functioning, competitive market. My organization has responded to about 40 RFPs in the last year, and in most instances those RFPs had anywhere from eight to 40 competitors responding. In the short-term market, there are thousands of kilowatt-hours being traded in the New York, NEPOOL and PJM areas every year. I know of some customers who have made a strategic decision to use very little of their own generation, and are buying up to 50 percent of their requirements in bilateral transactions. I look forward to selling to them.

General discussion:

:_As a regulator in a state which supposedly has a very well-developed bidding process, and watching both the IRM process and also the RFP process, I can tell you without question that we just do not have a level playing field. As we move into a more competitive marketplace, we regulators are facing another problem, because on one hand we're telling utilities, "Be more competitive;" "Operate like you're in the private sector;" "Think like entrepreneurs.", and this means that, as regulators, we have to give them more discretion.

At the same time, absent the level playing field, increasing discretion can lead to undesirable outcomes. Tying up the marketplace with long-term contracts with which utilities may be trying to buy time in the rush to become competitive has been very troublesome for me. I have refused to sign any settlement that has such a provision in it because, to me, they act to delaying competition.

We tried to hold a proceeding about a year ago on the issue of short-term power sales, to see if we would get any takers. No one came to our hearings. We were told everything was fine. Now the link to the long-term market is interesting, because there are all of these short-term deals available now. I don't see any long-term contracts on capacity being signed.

: The California Manufacturing Association, whose 800 members want to be power buyers, is one compelling reason why retail wheeling must be part of the market solution. In the future, there will be long-term contracts, particularly for industry, and there will be T&D companies that want to lock in inexpensive power.

My organization owns six power plants in New England, but is not able to be an active player in the wholesale power market. Contracts to which these plants are subject stipulate that all power be sold to the contracting buyer; any excess power must be sold to the contractual buyer below regular price and not to anyone else. Such restrictions are keeping independent power producers out of wholesale markets. The utilities also own and operate the power pools. The industry needs structural change.

: An anti-market bias afflicts most industry reform proposals. First, there is the thesis that historic obligations have to be protected. The independent power producers have obligations that they want protected, namely the now-uneconomic power purchase contracts. Are contracts really that sacrosanct?

There is also a notion that regulators can be instruments of the transition to competition. We have one example of that in the history of the world, and that was Alfred Kahn. They don't make a lot of Alfred Kahns; it is worth asking if this notion that somehow the regulators are going to guide us into a competitive future, i.e., unemploy themselves, is terribly realistic. There is a lot of misinformation -- things that are just plain wrong. The U.K. experience, which everybody thinks he understands and nobody knows anything about as far as I can tell, is often cited as a model for industry reform in this country. Actually, the U.K. is in turmoil now because the system there doesn't work. Profits are extraordinary, dividend rates are soaring beyond anybody's expectation. It's not clear that the British system is at all desirable, and the notions that have been sold as benefits of "regulation" are really the benefits of *privatization,* which have nothing to do with competition -- they were bloated organizations run by the government.

Finally, the analytical frame of reference used in the discussion seems often to rest on operations research principles, not competition. Examples are the notion that third parties can somehow protect themselves in bilateral negotiations, or that it's necessary to predict the consequences of competition. You can't predict the consequences of competition. That's what competition is. We want entrepreneurs to come in and be creatively destructive; we want them to pull a Schumpeter and essentially destroy the structure of the industry and its pricing structure and its asset values.

Cries of "Please don't take away PURPA!" and "Leave my contracts alone!" notwithstanding, we are probably driven to restructure the industry. This reform would likely require very rigorous antitrust enforcement to prevent the people from using pools to keep competitors out of the business. Competition is about pulling the plug on the existing system and seeing what happens.

Predicting the effects of reform would be of less interest as a policy question if the proposal was literally to deregulate everything and allow competition to unfold. That is not, however, anyone's proposal, because the center of this system is a great big monopoly. Either implicitly or explicitly, it is necessary to define appropriate access rules, pricing rules, and property rights for the transmission system. That system has to be designed and administered by regulators to avoid monopoly abuses. If the proposal is to simply deregulate and let the market evolve, that's a different discussion. In any reform proposal, there is still only one integrated grid. We are faced with a transmission monopoly in the middle of this industry -- how are we going to deal with it?

: Particularly in Massachusetts, it has been the municipal utilities, who are not encumbered by the bidding process, that are most active in the wholesale market. Most investor-owned utilities are so enmeshed in the bidding process that they cannot take advantage of opportunities in the wholesale market right now.

: There is an inconsistency between the position that contracts should be honored and the argument that contracts specifying that all your power be delivered to a certain customers should be opened up to allow participation in the short-term market.

: It is important to keep discussions about the end point of the transition process distinct from discussions about the transition itself. A market in which generation is fully competitive is a common end point of many proposals. The question is, how do we get from here to there? To answer this question, we need to address questions of phasing out existing obligations.

Regarding the suggestion that we auction off utility assets at book value, how do we deal with the problem that the assets that are likely to go are the ones that are the least troublesome from the perspective of stranded cost? This auction proposal appears to present an opportunity for people to cherry-pick from the utility system. It seems likely to leave the utilities with the same dogs that they already have, and it's not clear that we get rid of the stranded asset problem.

If we were to set up a system where regulators and other parties still had some leverage over utilities, incentives might then be structured such that it would be in the utility's best interest to conduct such an auction. Many have thought such auctions through in private, while public discussion has lagged behind.

The hope of this proposal is that the rates established by this auction would turn out to be less than the current regulated rate associated with that same asset, while still being high enough to satisfy the buyer. If so, you get some rate reduction and you move the asset from the books to a contract relationship. However, I would not recommend testing this model on a case of nuclear decommissioning.

: The market does not yet offer truly open transmission access, which is a basic prerequisite for a wholesale market. The fact that regional transmission groups (RTGs) are not yet up and running is one piece of evidence that this is true. The formation of RTGs was attempted before in New England and failed, and now we're seeing second attempts; perhaps the time is ripe now.

Will open transmission access ensure wholesale competition? If we had access with retail competition, the differential rates one observes today between different franchises might disappear over time.

: The FERC is indeed carrying out its mandate under the Energy Policy Act to make the wholesale market competitive by applying a comparability standard to service and tariffs. While developing these comparability provisions is a slow process, every utility will ultimately have these provisions, and we will have "real" access. But are FERC rulings on comparability alone sufficient to guarantee an efficient market outcome?

: The comparability standard may be the correct standard, but if you are relying on someone who has a self-dealing problem inherent in their own competitive business or that portion of business that is competitive, you haven't solved the problem. That's what's driving everybody in California and elsewhere to think about how to solve the self-dealing problem. Utilities themselves in California have acknowledged that this is a problem, and that they need to have a market structure which is free of serious self-dealing problems. Two basic proposals can help create such a structure. The first is divestiture and vertical disintegration; the other is a "Poolco" model which foresees an independent entity that controls access to the grid and economic dispatch. These models are not rival proposals; rather, they are functionally equivalent. Imagine a pie representing the integrated utility: we've got "slices" of generation, transmission, and distribution, and we have a slice called system operation, a critical function. It's the control of that function that determines who gets access, who can come in as a competitor, and whether their transactions will be implemented or not implemented. So, in considering models of the divestiture process, i.e., spinning off generation, transmission, and distribution, you need to ask yourself, "Who's running the system now?" There needs to be an independent core of people controlling the access to the grid, operating dispatch, and balancing the system on a moment-by-moment basis. The Poolco model basically recognizes this from the outset, and creates that entity to begin with.

: A complementary piece of the solution is the role of RTGs. Their function at the local and regional level, coupled with the FERC's policies, ought to provide a mechanism on a day-to-day basis to support long-term transactions that can be entered into freely with immediate information for all parties.

: The gas pipeline industry wasn't forced to divest its exploration and production operations or its marketing operations. The companies were able to operate their pipelines in a way such that there was no perceived self-dealing. How is avoiding self-dealing while running a pipeline any different from doing so while running a transmission system?

: The pipeline and transmission businesses also differ in the magnitude of upstream investment: no pipeline system has anywhere near the investment in upstream assets that is typical of the electric industry. Those companies on the gas side that did have upstream assets as well as contracts between those upstream assets and the downstream operations had those contracts challenged. Everyone in the industry spent time in court because the structure of companies' assets engendered the perception in the marketplace that they were self-dealing.

: Enron Marketing and Coastal Marketing are both large gas pipeline networks, which also have among the largest marketing operations in the country. These marketing affiliates are totally separate from the pipeline companies bearing the same name. FERC Rule 497, the marketing affiliate rule (the equivalent of which is also needed in the electric business), explicitly limits all interchange of agreements between a regulated pipeline system and non-regulated marketing affiliates. Their staffs are completely separate from one another. The only exchange of information permitted between two such entities is made publicly available on an electronic bulletin board.

: The FERC's AEP decision didn't "order" comparability -- it merely set forth a vision of what the FERC saw as generally desirable in terms of comparability. Interestingly, tariff filings subsequent to the Order voluntarily incorporated comparability. This acknowledgement of a *de facto* standard has been building on itself, and the FERC is monitoring whether this standard is developing in a desirable way.

A key question for regulators is how to motivate a high-cost utility to be vigilant in trying to get its prices down as quickly as possible, as opposed to trying to maintain the book value of its assets.

: There are three major issues facing regulators in the transition to competition: (1) drawing the jurisdictional boundary (federal/state), (2) designing appropriate regulatory structures, and (3) identifying coherent policy goals. The often-articulated but sometimes conflicting goals of lower prices, greater reliability, customer choice, and a clean environment need to be reconciled.

: The FERC is doing a good job of what it has the authority to do -- namely, to create and expand wholesale *access*. However, the FERC cannot create wholesale competition. It is, in fact, legally barred from doing so. Expanding access will increase new entries into the wholesale market. It will do nothing, however, to allow incumbents an easier exit. Workable competition requires free entry and free exit, and exit is now very expensive. Direct access is the only way to achieve free entry and exit.

The real beauty of direct access, however, is that it will change all those mindsets that are stuck in the age of regulation. With direct access, regulators have no choice but to change. Some of them won't have jobs. Utilities will have no choice but to change. One of the choices that they will make under direct access will be whether to divest themselves voluntarily -- unless they do, they will continue to be regulated. And if they want to compete, there's no benefit in being regulated as a competitor.

: The auction proposal presented this morning would create an environment which would indefinitely preserve the monopsony purchasing power of the regulated utility in a single buyer, single franchise model. If this outcome is viewed as desirable, then the proposal voiced today might be an attractive way to go. If that's *not* what we want to do, then we want to think carefully about what it is we're trying to structure. Some of the solutions that we would devise for the wholesale market have implications for the robustness of competition in the marketplace -- we ought to think about ways to make those things compatible. The FERC is thinking about what to do on transmission access, for example. It may only have reach over the wholesale market, but it can structure that market in several ways that leave states either more or less able to manage it with their authority over the retail market. Interestingly, the California discussions actually come to a somewhat different conclusion than do the papers presented this morning.

2 *Competitive Market Structure: A Review of the California Debate*

This discussion began with an update on the process currently before the CPUC and an overview of the pool approach as it is discussed in California. The first presentation explored how a bilateral market in California might work, followed by a description of the latest informal developments in the state. Finally, another institutional perspective was offered on industry reform in the state.

First speaker: I'll begin by summarizing where the California debate stands procedurally. All of California's utilities are currently charging over 10 cents on a system average basis, which is substantially above the national average. These high rates have certainly exacerbated a downturn in the state's economy. The forces that have produced these high rates are attributable to the actions and decisions of many different parties. Power contracts signed by the utilities, nuclear plants built, qualifying facility contract payments, preferences for renewable resources, very aggressive demand-side management programs, and other public policy programs like low-income ratepayer assistance have all contributed to the level of California's rates.

The Blue Book of the California Public Utilities Commission set two priorities: (1) Where possible, a *competitive market* should be established. Generation was clearly identified as a potentially competitive segment of the industry. Retail competition was seen in the Blue Book as a means of bringing the benefits of competitive generation to their fullest fruition. This would raise issues of stranded costs, non-discriminatory transmission access, and the status of the utility as a power supplier. (2) The second priority of the Blue Book proposal was *performance-based ratemaking.* In August, the Commission approved a third piece of the performance-based proposal for San Diego Gas and Electric (SDG&E), which is now regulated almost exclusively on a performance basis. SDG&E presently makes its money on purchasing power and on beating benchmarks on the cost of energy. Having a new player like Enron come into the market to try to come up with cheaper sources of power than what SDG&E acquires is now very much in SDG&E's own interest.

93 parties have been active in these discussions: 20 utilities (including in-state and out-of-state IOUs and municipals), 26 customer groups (large customers' associations and consumer advocate groups in California) and several governmental agencies. The U.S. Department of Energy has come to the Commission and made presentations, and the California Energy Commission is also involved. In addition, 22 parties who would fall into the category of power marketers -- IPPs, QFs, and power developers -- as well as another nine environmental groups, participated. Full-panel hearings in front of the Commission are still being held. The first panel on direct access and customer choice has been concluded, and the Commission set a second panel on that subject for October 24. In parallel, public participation hearings are held in which presentations are invited from anyone. The Commission has targeted the end of the year for a decision.

The major issues that have come up in the California debate are much the same as those we have been discussing today. At least four different camps have voiced opinions on the subject of direct access. One camp says that immediate access would be best; another group suggests a phased-in process, stretching from 1996 to beyond 2000; and a third group that is suggesting that still later would be good. SDG&E's position is that it can provide direct access to all customers by 1998.

The method of providing direct access has also brought forward differing opinions. The classic retail wheeling approach is advocated by some, with some sort of system operator left in the middle. SDG&E and Southern California Edison (Edison) have proposed a "Poolco" model, with SDG&E proposing an efficient direct access method.

There's also been debate about whether it is possible to create a transparent spot market for power, so that customers and regulators would have the ability to look at the prices being charged. Regulators want a visible market so they can see the prices; other parties are questioning why the regulators would need to know prices in an open market.

As for transition costs, a rough estimate of these costs statewide is $10 billion, about half of which is nuclear facilities and the other half is power contracts, mostly with qualifying facilities (these figures are based on the California Blue Book's methodology of comparing current marginal costs with nuclear plant and contract prices).

Regarding operational issues such as control of the electric grid, everybody seems to agree on the idea that there has to be a system operator, but there is no agreement on what the list of functions for that operator ought to be. Should the operator's functions be limited to operation of the grid to ensure reliability (the minimalist approach), or should they go so far as to include elicitation of bids for hourly spot market prices, thereby creating the visible spot market? One of the pivotal discussions in California--with Bill Hogan on one side of the table and Jeff Skilling on the other--has been which of these models will best meet the needs of all parties.

Other key issues that are being addressed include what to do about some of the public policy issues that the Commission and the Legislature in California have been so active on in the past, including demand-side management, renewables, and low income programs. We also don't know where the Commission is ultimately going to come down on integrated resource planning. Is W the responsibility of the market, the regulator, or the local distribution company?

The Commission is looking very hard at performance-based ratemaking. It has been implemented almost 100 percent for SDG&E, and the Commission is currently reviewing proposals of both Pacific Gas and Electric (PG&E) and Edison.

Regarding utilities' future role as owners of generation, there have been a wide range of proposals from complete spin-off and sale of the generation facilities, to separating them out contractually, to leaving the existing facilities with the local distribution companies. ERAM--the decoupling of sales and revenue--is something that California has had for over a decade. It was instituted primarily to ensure that there were no disincentives for demand-side management programs. A question has arisen whether payments from customers that choose direct access should be exempted from the ERAM mechanism and thus depend only on actual sales to those customers.

Finally, the obligation to serve is an issue that is being characterized differently by different parties. Some parties would have the local distribution company retain the obligation to provide reliable, cost-effective electricity. Another camp has argued that the function of the local distribution company should be to provide access to the market and that the market itself will determine the supply and provide the supply to customers.

Let me talk a little bit about SDG&E's proposals, which relate closely to some discussions from this morning's session. SDG&E has proposed vertical disintegration: separation of the monopoly and competitive functions. Generation would be sold at a minimum price to an affiliate, and transmission assets would be in an unaffiliated company. If there is no one out there that wants to buy all the transmission in California, then SDG&E would become a limited partner and divorce itself from any sort of control of the transmission. The local distribution company would continue to be the monopoly providers of local service.

The centerpiece of SDG&E's proposal is the formation of an independently-operated pool that would make an efficient spot market possible. Under its direct access proposal, customers would have access to the energy out of the pool, priced at the pool price. The larger the independently-operated pool, the better. There's no reason why it should not be the Western System's Coordinating Council size, but it would, of course, be feasible on a smaller scale.

The chief role of the pool is to dispatch the system. In a situation where there's a finite amount of generation and one transmission grid that connects all generation, there really is only one most efficient dispatch. That's what this pool should strive to provide, because the pool is going to be the default provider for any customer. It's going to be the provider in the case of imbalances between contract supplies and actual load, and it's going to be the provider for those customers who do not enter into outside contracts.

I just saw in *USA Today* that 60 percent of the country still takes long distance service from AT&T. I don't know how many of that 60 percent made an affirmative choice to take AT&T or simply stayed with AT&T because they felt they didn't have enough information to change, it was too much of a hassle to change, or whatever. I suspect that, in moving from a regulated electric industry to a direct access industry, there will be a large number of default customers who simply take what is provided with the least amount of effort on their part. For those customers, we want the supply to be as efficient as possible.

SDG&E's efficient direct access proposal could be implemented by 1998. If all involved parties in California agreed that SDG&E's model was coherent and logical, we could get it done a lot sooner. Such agreement is not going to be quickly forthcoming, so the schedule proposed includes time for people to argue about the date and for the Commission to come to some determination. The proposal has one additional step, which can be accomplished concurrently: taking the existing pooling function and making it an independent pool.

SDG&E's proposal accommodates all types of bilateral transactions. Under its proposal, the pool operator--who focuses on reliability of the system and setting up an efficient hour-to-hour spot market--has no idea what bilateral contracts might exist between customers. Bilateral contracts are financial instruments between suppliers and customers; they can take whatever form the supplier and the customer agree on. I expect there to be an explosion of ideas of what form electric service could take, given this flexibility, with respect to time, load conditions, price, etc. The pool should have no role in interfering with those contracts or preventing those contracts.

The electric industry is an instantaneous industry. Imbalances happen instantaneously for any number of reasons. It doesn't require misfeasance or malfeasance by any contracting party: it can be lightning, wind, rain, airplanes, or simply changes in load. A major benefit of a power pool is that the combination of dispatch with an efficient spot market creates the ability to settle those imbalances at an efficient price. It also provides default supply to customers who may not have a contract covering the situation they find themselves in.

Power pools also resolve some very significant jurisdictional issues. The pool itself would clearly be a FERC-regulated function, while sales out of the pool to the customers would be a state function. A clear demarcation between these activities is possible because the local distribution company would actually buy the power from the pool and deliver to the customers at the pool price, while the state regulator would retain total jurisdiction over tariffs of the retail company. What is really separated out from state jurisdiction is the price of power, as distinct from all the other attributes of retail service that are currently in retail rates.

Finally, SDG&E's poolco proposal would include locational prices -- that is, it would determine prices for different locations with regard to transmission congestion, and would create different spot market prices in different locations. This feature will provide the appropriate signal for where power is truly cheapest (rather than assuming that there are no costs involved in getting power to the market), as well as where new transmission capacity might be cost effective. Can we create a more competitive generation sector by selling off generating assets? SDG&E owns two large fossil plants within a transmission-constrained area; those plants are required to operate about one-third of the year because there's no other way to get power within that constrained area other than turning those plants on. If it simply sells those plants to an independent party, it's done nothing to create a more competitive market -- it's just changed the name of the party who has the market power created by the transmission constraint. What SDG&E has proposed is that the plants be separated out and be given contracts that limit their ability to assert market power for a transition period, and during that period other suppliers would have the opportunity to come in, build capacity in that local region, and compete to supply customers in the local region. It's through the introduction of additional competitors that the market will develop, not by virtue of a mere change in ownership.

Discussion:

Question: Does SDG&E's proposal imply a single dispatch area?

: While coordination ought to be as tight as possible, we would probably see different control centers, each maintaining one or more spot prices. Efficiencies could be gained if the grid in the western United States were operated like some of the tight pools in the East. We could accommodate this design by creating an independent pool operator.

Question: How might a continued role for the ERAM be possible under a direct access system? Might it be handled through a wires charge?

The ERAM would be limited to CPUC jurisdictional revenues, ie, it would need to separate out those functions--and associated revenues--that are going into the competitive market. What ERAM does today through a general rate case is to set total company revenues for the year as the *target revenue;* utilities recover that revenue regardless of the level of sales. What could be done in the future would be to set the target revenue based on the remaining state jurisdictional service -- which would no longer include the generation components -- and then the mechanism would continue to operate as before.

Question: Would the distribution company have the option of buying from the pool and offering long-term contracts to its customers, to help them manage the risk associated with spot prices?

: While the idea that the local distribution company needs to be a provider of supply to its customers has a long history in the industry, it need not be the case. Distribution could be an aggressive, unregulated marketing function that any number of potential suppliers would want to get into, in which they would bundle products for residential customers. The appropriate model would be to take the local distribution company out of the generation business altogether. Should local distribution companies be forbidden from entering that market?

: They could enter the market as an unregulated affiliate that focused on putting supplies together.

Second speaker: In developing its response to the California proposal to restructure the electric industry, PG&E heard loud and clear from all of its customers that they want choice. Hence, in designing its response, it built that feature in. Its proposal outlines a system based on existing institutions and on its experience in the wholesale market as well as in the gas industry. PG&E believes that direct access is technically feasible, and can be implemented while maintaining reliability at its current level.

Within the western U.S. where PG&E operates, there are more than 70 utilities, municipalities, and government agencies, as well as about 500 Public Utility Districts, cooperatives, rural electric associations, and government preference entities. There is also an extensive network of investor-owned transmission as well as municipal-owned transmission systems that interconnect the entire West. This network spans about a dozen states, two Canadian provinces, and the northern part of one Mexican state. The western U.S. bulk power market comprises about two billion dollars worth of transactions. A number of the transactions occur under the Western System's Power Pool, which is already a very efficient market. California also has about 800 qualifying facilities in operation, representing about $4 billion in revenue (apart from the $2 billion in wholesale transactions).

There are currently about 40 control areas and a number of other entities that operate as control areas, but are not specifically designated as control areas. Within each control area, each entity operates under an economic dispatch regime, taking into account operational constraints as well as existing contractual arrangements. Within California, PG&E delivers power to a number of dispersed municipal loads, from dispersed supplies. PG&E also has supplies in the Pacific Northwest as well as in the southwest that are transmitted into its control area. In any given month, PG&E's operators coordinate the schedules for several thousand transactions between the Northwest and Southern California; within the area, PG&E coordinates the transactions for at least that many transactions for the various entities in northern California. So there already is an extensive amount of bilateral trading, marginal trading, and spot market trading taking place within this area.

PG&E has proposed a system that uses the existing wholesale framework to make direct access possible. For example, there are today eleven cities for which PG&E provides transmission service, including Sacramento, Modesto, and a number of municipal utilities.

The proposal is to build on this framework to provide direct access customer service to a supply coordinator. It does *not* envision individual contracts for each transaction or with each customer--most transactions can be handled with tariffs.

In the transition period to direct access, those customers not yet eligible should not be harmed. PG&E has proposed an orderly phase-in of direct access; at the risk of not recovering transition costs for some utility generation. There will be transition cost recovery for above-market payments for QF contracts and for regulatory assets. Customers will continue to receive the benefits of social and . environmental programs; there will be a performance-based mechanism put in place for non-competitive regulated services.

There will be no need to determine transition costs for nuclear facilities or for any other utility generation assets. A phased-in schedule was proposed that extends the current PUC schedule. It begins at the 1/1/96 proposed date, but extends the phase-in period for a total of six years. Depreciation of nuclear facilities will be accelerated. By the time all customers are eligible for direct access, it is projected that these assets will have been written off.

Eligible customers will be able to choose either to continue with utility service or to buy from any number of suppliers in the marketplace: e.g., from brokers, IPPs, Qfs, or other utilities. They can choose what level of service they want -- interruptible service, firm service, extra reliability if they're in the manufacturing sector, etc. They can set the price, terms, and conditions, they can have price risk management features -- a whole array of financial instruments. Moreover, they can choose the level of unbundling. What that means is that customers can choose to act, in effect, as their own portfolio manager or supply coordinator, or they can assign someone else to perform that function. If they choose to provide that service themselves, they can seek control area services from the marketplace, or have others supply these services on a more bundled basis. Tariffs will be in place for all of these services, so that information will be known ahead of time. All of these services will be unbundled before direct access begins.

The role of the supply coordinator is to be a single point of contact for the grid operator as well as for the customer. The grid operator will interface with the coordinator, the coordinator would provide schedules to the grid operator just as municipal utilities provide hourly schedules to our operators today. The supply coordinator would have the responsibility to match loads with resources, and also to provide control area services. They could contract for these, they could own resources, or they could buy them from the grid operator at the unbundled tariffs. For imbalances arising because of emergency conditions or inadequate standby supply, there would be a settlements process whereby the grid operator and the supply coordinator would provide information, perhaps to an independent settlement agent who would determine who should pay whom. The supply coordinator role is basically that of a portfolio manager: meeting the reliability standards for operations and participating in the settlement process. The grid operator, initially the utility, would provide non-discriminatory network service, offer unbundled control area services, and ultimately, have responsibility for assuring the reliability of the power control area and honoring existing contracts and agreements.

This proposal requires certain information that doesn't exist today. In particular, it requires a spot market price. A number of utilities, power marketing agencies and municipalities are trying to develop a wholesale spot price index, which will be in place by 1995. PG&E is actively working with other independent reporting agencies who could fulfill this reporting function just as is done in the gas business. The wholesale spot price would be transparent, utilities would report transactions on the wholesale side, the parties to these transactions would remain anonymous, but the price would be reported, allowing a distinction to be made between economy energy and spot capacity.

Metering requirements necessary to implement this proposal may be beyond what we have in place today. PG&E has proposed that the utility offer basic metering services sufficient to perform after-the-fact settlements. We need to have the procedures and tariffs for settlements clearly articulated before direct access begins. To the extent that there would be disputes in the settlements process, some type of mediation or arbitration process could be used to allow them to be resolved quickly.

In summary, PG&E's proposal is designed around customer choice that would take advantage of existing systems and of our experience in the wholesale market as well as in the gas market. This proposal recognizes that there cannot be cost-shifting between direct access customers and non-direct access customers. Nor can reliability be compromised. Ten years ago, California saw 800 qualifying facilities and independent generators come onto the system. At that time, a lot of operators raised concerns about reliability. Today, many would argue, reliability is better than ever. Twenty or thirty years ago, when 500 Kv lines were put in place connecting California with other states, people also raised the issue of reliability. Ultimately, these lines enhanced reliability. The lesson would appear to be that significant market changes can be accommodated without sacrificing reliability. Reliability issues have been handled well in the wholesale market, and we will also manage to do it in the retail market. We will have price transparency, economic dispatch will continue, and there will be a settlements process.

Discussion:

Question: Would you elaborate on your economic dispatch concept?

The grid operator would schedule the transactions between the supply coordinator on behalf of PG&E's customers and the suppliers into their system. The supply coordinator would provide hourly schedules to operators and, just as in happens in the wholesale market today, those schedules would probably change at 20 minutes to the hour if generation or the load is going to change. PG&E would continue to have a certain level of resources necessary to follow load; currently, this is about 400 MW. This capacity does not necessarily need to be owned by the utility; it could be handled by contract.

Question: How would you handle phasing-in direct access for different customer classes?

: The gradual nature of the proposal is designed to glean lessons from the evolving experience, to see what additional institutions or mechanisms need to be put in place. The concerns about phasing everybody in at the same time are that, first of all, metering infrastructure is inadequate. Second, there are lessons to be learned as we engage in these retail transactions that should be fed back into the system's evolving design. This adaptive approach is superior to attempting to anticipate problems.

Third speaker:

After the commission issued its Blue Book on April 20th, 93 interested parties offered alternative scenarios for dealing with industry restructuring. Among the questions on which the Public Utilities Commission invited comments was the following: "Can present market institutions adequately deal with direct access? If not, how should they change?" In response, SDG&E initiated a competitive power market working group chaired by Charles Stalon; to date, the group has met twice and further meetings are scheduled. The working group comprises about 65 participants representing a broad cross-section of interested parties in the California industry reform process: IOUs, municipal utilities, consumer advocacy groups, customer groups, IPPs, the Environmental Defense Fund, the Department of Energy, FERC, and the California regulatory bodies.

As part of the group's activities, a smaller committee was commissioned to try identify and compare different possible market models. This presentation and the supporting paper draw heavily on the work of this smaller committee. Nonetheless, this presentation does not represent their work product, it only represents my views on where they are.

How would various models function in trying to accomplish a transaction between a direct access end-use customer and a supplier? The three models lie at different points along a continuum -- of course, any number of other models may be conceived of that occupy intermediate points along this continuum. In the interest of time, this discussion will neglect a number of interesting issues such as transmission pricing and spot pricing, focussing instead on the basic structures and contractual relationships in each of the three alternative models. All three models contemplate direct access from the end-use customer to the generator, albeit implemented in different ways. In addition, we have not yet dealt with the efficient direct access proposal that Bill Hogan has advocated, although as you'll see, it probably could work in at least two of the models, if not all three.

The working group has focused on operability of the network under direct access: ensuring the reliability of the system, addressing the economics of total system operation, and identifying whether the costs can be equitably allocated among the various participants. For clarity, I'll refer to the models with the following shorthand labels:

(1) Traditional retail wheeling model
(2) Opco model
(3) Poolco model

I'll briefly characterize the three models.

(1) Traditional retail wheeling model

This model contemplates a generator that is able to contract directly with a customer and to acquire transmission service (bulk power and distribution) through the grid. It also provides for the scheduling of power through the grid and describes that information to the transmission system operator. The generator notifies the transmission system operator (TSO) of the schedule of power through the grid. Some level of control over the generator may be exerted by the TSO to prevent overloads in emergencies, but otherwise the generator provides the schedule. The TSO would need to monitor actual and scheduled delivery, and actual and scheduled consumption, and then, by some mechanism, settle imbalances between each of these. In the purist model, this is accomplished at a contract price. The TSO is an individual utility utilizing its own transmission system. Where the generator is more than one utility away, this type of arrangement would be "pancake&' two or three times in order to get through the necessary number of systems from the generator to the ultimate customer. Handoffs are made from one utility to another as is done today in the wholesale power market.

(2) Opco model

The second model has been called Opco, meaning simply "operational company." The Opco model envisions a pooled transmission grid and a single independent transmission system operator providing oversight control for the operation of the generation and transmission grid. Again, the generator would provide to the transmission system operator a schedule for delivery through to the customer. We contemplate that some portion of that generation would be offered to the transmission system operator--who has no resources of his own--as flexible generation to be dispatched by the transmission system operator at the price bid in, ie, at the market clearing price at a particular location. Because the transmission system operator is independent and has no generation of his own, he has to be able to acquire generation control in the spot market. Thus, the generators would provide to their customer a schedule and the price at which they are willing to be controlled up or down by the transmission system operator. As in the first model, the settlement system foresees that the difference between scheduled and actual delivery would have to be monitored for each generator and for each customer. In this pooled model, however, because of the availability of locational market prices, we have the opportunity to use a spot market price to settle any imbalances. This model incorporates some amount of scheduled generation and some amount of flexible generation.

(3) Poolco model

The third model, termed Poolco, is similar to the proposals that both Edison and SDG&E have put forward. In this model, the generator would contract directly with the end-use customer with a contract for difference or a "swap contract." It establishes the price, terms, conditions, and reliability of delivery; generators would submit bids to the transmission system operator consisting of the price range over which they are willing to be operated. Likewise, customers could bid in the price at which they're willing to be served or not served depending on whether they have contracts. The transmission system operator would then dispatch generation on the basis of overall economics. The amount of power which is delivered is then priced at the local spot market price. For power received and power delivered back out, the contract for difference swaps that market price for the predetermined contract price.

Is a transmission system operator required in the wheeling model? Certainly -- the TSO is the utility dispatcher of today. A TSO is also required in the two pooling models.

The first difference between the models is that the transmission system operator need not be independent in the wheeling model. It is the utility operator, so there is no independence. In the two models having a pool, however, it is important that the TSO be independent so that the dispatch of the generation is completely unbiased with respect to ownership.

How much of the generation does the TSO have control over? In the traditional wheeling model, the TSO dispatches his own plants and if there were constraints, he would also have some kind of emergency dispatch authority over the direct access facilities. Under the Opco model, some portion of the plants would be bid in flexibly in order to provide the TSO the ability to control the system. In the Poolco model, we contemplate that most plants, if not all, would be bid in flexibly in order to take advantage of the dispatch.

What does the supplier, the generator, have to provide to the TSO in terms of information? All generators have to give notice of what they intend to produce and what their customers intend to use. Under Opco, those that choose to put through a full schedule have to provide that information. Under Poolco, the plants have, to state the price at which they're willing to be dispatched, and over what operating ranges.

Does the generator provide a price? Not under the wheeling model, because generators are not expected to be dispatched up or down. Under Opco and Poolco, the flexible plants do provide prices.

Where there are imbalances, how are they dealt with in each of the models? In the wheeling model, they would be specified in whatever contractual arrangement existed between the direct access customer, supplier, and the grid operator (the "host" utility). Under Opco and Poolco, they could be dealt with spot prices because both pooling mechanisms develop local spot prices at both supply and customer load levels.

Ancillary services such as control area services, spinning reserve, and voltage support could be tariffed or specified in contracts in the retail model. They can be bid in in both the Opco and the Poolco models and priced either on an average basis or by locational spot differences in these two models:

As for transmission rights, we spent some time discussing whether transmission rights could be tradeable. We contemplate that, in the two pooling models, it's necessary to have tradeable transmission rights in order to provide efficient locational signals. Under the wheeling model, it's certainly possible, it's just not clear which way it would be implemented; this would be decided on a utility-by-utility basis.

Regarding settlements and balancing of differences at both the supply and the customer end: Under the wheeling model, the settlements are the loads and generation net of the nominations, namely, the "differences" in the contract for differences. Under Opco, the same holds for those that are scheduled through; for those that are not scheduled through, it is simply gross loads and gross generation. Under Poolco, the settlement is just gross loads in and gross generation.

All three models allow commercial bilateral contracts between end-use customers and suppliers; also, all three models would be completely consistent with connections between the entities providing these services and outside entities, ie those within the same electrical region but not participating in either the pool or in direct access.

Under the wheeling model, adequate supply to keep the lights on would be established by the market. In particular, as more and more customers became eligible for direct access or when new customers needed load, distribution companies would be contracting for supplies; essentially, we would be depending upon a market signal to bring in new supplies. None of these models envisions any residual utility role other than providing transmission and distribution.

If a customer has contracted with a generator who is not available on that hour, that would be treated as an imbalance. Under the wheeling model, that imbalance would be dealt with by the TSO having to acquire backup supply from a flexible generator, unless he had generation of his own. In the wheeling model, the TSO has no generation to call his own, so he would have to acquire backup supplies. That would then become a settlement price to the customer whose generator had tripped off or alternatively, to the generator who failed to deliver. Likewise, in both Opco and the Poolco models, price would be the signal and incentive for new generation entry.

How do these three models deal with cost-shifting between entities? Under the wheeling model, one can structure the transmission and distribution contracts in order to prevent cost- shifting. It will, however, take a great deal of diligence and possibly depends on the rate design; close regulatory scrutiny will be required to prevent cost-shifting. In both the Opco and Poolco models, it would have to be established who owns which rights over which transmission lines to deliver physical power.

Power pricing transparency could be specified in the contract and could be achieved, as suggested by the previous speaker, by some outside indices. In both Opco and Poolco, it would be developed automatically by the bid spot prices at each location for the generation that is flexible. In either of those models, price could easily be published and made available to all market participants.

As for transmission price under the utility-specific wheeling model, there would be a utility-specific transmission price filed with the FERC; where you were moving through multiple systems, you would have multiple transmission tariffs to deal with. Under the pooled approach, you could get to a single methodology for pricing transmission, it would obviously have to be filed and approved by the FERC, but it might be possible to move through several systems with a single tariff.

Jurisdiction for the wheeling model either belongs to the FERC, or is disputed between FERC and state. You can reach essentially the same conclusion for both Poolco and Opco depending on the role of each at the retail level. As stated under the efficient direct access proposal, the dispute can probably be sidestepped, but for models that foresee transmission service all the way through, these arrangements are probably subject to dispute.

We talked earlier about generation investment incentives. On the transmission side, the host utility would be responsible for identifying new transmission and would enter into negotiations with customers or generators that wanted to expand a constrained path. Under both the Opco and the Poolco models, there is a clear opportunity to identify the cost of congestion simply by the cost of redispatching to relieve the congestion; that price differential can easily be made available to all of the market participants, providing a market-based signal to relieve a constraint as soon as it exists. Coupled with RTGs or their equivalent, we can probably achieve efficient transmission expansion when there is congestion.

Certain support systems are needed under each of these models. Under the wheeling model, each utility needs to provide economic dispatch for the portion of the generation it uses for control, a settlement system, and a contract tracking system for generators' nominations and scheduled loads of the customers. Under the Opco model, essentially the same types of systems are required, although the extent of the tracking system depends on how many of the contracts are scheduled through and how many are allowed to be flexible. Under the Poolco system, the contract tracking system goes outside of the pool operation. It becomes the responsibility of both the suppliers and the customers to track their own contracts.

Finally, all of the utilities in California are party to existing contracts to provide a variety of services to other agencies, including other utilities; all three of these models are compatible or can be made compatible with the existing contracts. Nonetheless, we should remember that expansion of a pooled approach to include more participants and fewer restrictions makes fora more efficient operation.

<u>Fourth speaker:</u>

I've been asked to represent the institutional perspective of someone in the California regulatory scene. Three weeks ago, I was asked to playa similar role in a panel to explain what impacts, if any, the California direct access proposals had had. My response at that time was that it depends upon where you were standing in the mushroom-shaped cloud that rose over San Francisco. Since I work in Sacramento and the CPUC is many miles away, I get a very different view; I first recorded the view as very spectacular--awe-inspiring, even--but then we were expecting radiation coming down the road as soon as the fog started blowing through the Golden Gate.

I've since been looking around for casualties. I've suggested that one might be California's elaborate integrated resource planning process. Some regarded it as the model for the National Energy Policy Act. Others allege that it is the envy of other states (I'm not sure that's true). I estimated that this elaborate process would probably go away; in any event, it would be subject to major irradiation from the blast of competitive ideas and might not survive. I'm now observing that many of my colleagues in an agency that engages in central planning are now putting canaries in their offices and they're carrying small geiger counters around on their belts.

I was reminded of a book that I read back in the 1960s about the anti-colonial revolutions that were occurring in Africa. The central point the book was that, if you're going to destroy the old institutions, you ought to have a pretty good idea of what you put in their place before you do that. I think that message has been lost in California. Right now, there is a series of Public Utility Commission hearings going on. In each hearing, the parties are rapidly dismantling the last 20 years worth of cost of service regulation as well as the integrated resource planning process. Utility-sponsored DSM has been going on in California at investment levels of $500 million per year since the first California Collaborative, and is now being slashed. Shareholder incentives for DSM are being substantially reconsidered, revenue decoupling mechanisms, the ERAM, is proposed for abandonment, and all of our efforts at the Energy Commission to include environmental externalities in resource planning are being pronounced a failure, along with the whole paradigm of state and utility-operated integrated resource planning programs.

Given all the haste with which this dismantling of the existing regulatory system is occurring, you'd think that there is a broad consensus in California about exactly what we're going to do. In fact, there are enormous political and perceptual debates going on in

California about fundamental issues. There are in fact some very stimulating intellectual debates to which many who have appeared at the public utility commission have contributed. Most of the other debates have been dominated by misconceptions, misinformation, and misapprehension. Nevertheless, these debates are important and helpful. I'd like to highlight a few of those debates and summarize how some parties are positioning themselves on the key issues.

We've heard a presentation today from each of the three California utilities about their proposals to implement the PUC Blue Book. Interestingly, all three proposals are rather similar. The debate about whether there's going to be direct access is over. In California all three utilities are basically proposing direct access mechanisms; the main question remaining is whether it will be done with or without an independent pool. All the rhetoric heard in other for a about whether customers should or should not have choice, whether outside (non-utility) generators can or cannot be competitors, is beside the point; that debate's over. This is rather startling given that when the Yellow Book first came out from the Public Utilities Commission a year and a half ago, there was great debate about these issues. The tentative result after eight or nine months was the PUC leaning toward a concept that would likely not be described as direct access or retail wheeling.

When the Blue Book came out, proposing direct access, it didn't use the words "retail wheeling", and the psychology of the whole debate changed almost overnight. Some initial reactions claimed that the proposal was too extreme, the transition too fast, and the procedure not open enough. Within a month, the psychology of the situation had changed and such objections were no longer heard. Instead, everyone was figuring out how to implement the proposal. Everything is now moving much more rapidly in California since this change in the tide of opinion, because the PUC put out a proposal that was so radical that it just decimated everyone's preconceptions about industry reform. We are now building a market from the ground up.

One significant open question in current discussions is the speed of implementation of direct access for various customer groups. Under the PUC's proposal, the assumption was that the largest industrial customers, those at transmission level, would get it first. It would then be gradually phased in for commercial customers by, say, 1998-1999, and finally for residential customers by the year 2000. PG&E's proposal envisions direct access by 1996 for the largest commercial customers. Commercials and industrials are coming in much later in the decade, indeed, on into the 21st century. The residential customers don't get direct access until about the year 2008. By sheer coincidence, I suspect, 2008 is exactly the same date that PG&E would propose to have the accelerated depreciation of Diablo Canyon completed. SDG&E's proposal posits that once the pool is in place so that direct access can function efficiently, direct access will become available much faster. What San Diego has said today is that by 1998, the pool structure will be in place, no phase-in will be necessary, giving customers an immediate choice. If you're an industrial customer now, you probably like PG&E's proposal because it looks like you're going to be the first in line to get direct access in 1996. Looking at San Diego's proposal, you might say, "Pool or no pool, I'll have to wait for two additional years, and that's assuming that both of these concepts adhere to the schedule that's contemplated." Finally, you look at Southern California Edison's proposal; it says, "Well, we also think we can get a pool in place, we think that can happen fairly rapidly and we, too, would phase in direct access over a period of time." In an independent set of filings, Edison also said it thought direct access should be phased in a manner that does not create any more stranded investments than necessary. The way to do that is to allow direct access to occur only as a need for new power is developed in the system.

So you have three different schedules for direct access from each of the utilities. Based upon these schedules, you see all the other parties starting to line up. Those who believe they are first in line, ie, the largest commercial and industrial customers will say, "We want the PG&E proposal, we don't like Edison's proposal, so if Edison's proposal is POOLCO, there must be something wrong with POOLCO." Now we've got the debate about POOLCO mixed up with the schedule for direct access, whereas they're really two separate subjects. If, on the other hand, you're at the other end of the customer spectrum as a small commercial or residential customer, you look at this and say, "Well, gee, I don't seem to get direct access, if at all, until well into the 21st century. In the meantime, they've got all these opportunities for cost-shifting--how are people going to control that? Basically, we have to rely on the Public Utilities Commission to make sure that doesn't occur. Do we trust this arrangement?" Many are saying, "Sorry, we don't." Therefore, a lot of the smaller customer groups, such as TURN (Toward Utility Rate Normalization) or traditional ratepayer advocates, and ultimately the advocacy staff of the Public Utilities Commission, are all coming back and saying, "We can't have these extended schedules--let's compress the schedule." Unfortunately, that runs directly counter to Edison's view that you need to phase this in because it's all tied directly to how fast stranded investment gets taken care of. It also runs directly counter to PG&E's view which is that the schedule is tied directly to Diablo Canyon's accelerated depreciation. So proposals to compress the schedule run right into the problem of stranded investment.

Another proposal has been suggested by TURN. TURN purports to represent the interests of residential ratepayers; they have been very active intervenors. TURN's position is essentially, "We don't want to be last, so *why* don't we all be first?" The way that they would do that is to form buying cooperatives that would be community-wide; individual industrial customers would not be allowed to go and cut their separate deals. Instead, a popularly-elected board would oversee a buying cooperative that would act on behalf of the entire community. Well, that's an interesting way to get direct access to everybody, but then, of course, the question of rate allocation arises. From the perspective of the commercial and industrial customers who have watched rate allocation mechanisms work in popularly-elected municipal utilities, they are saying, "Wait a minute, this probably isn't going to be the best deal for us. If we could have access first, we could do anything." So, we've got these conflicting proposals from the various parties, each trying to solve the problems of timing and fairness. The utilities' proposals all make sense from their own perspective; what they're trying to do is to schedule direct access to correspond with whatever treatment they propose for dealing with stranded investment. Other (i.e., non-utility) parties are not looking solely at the stranded investment problem but at more general considerations of equity and fairness -- Why should any particular group of customers have to wait?

Among industrial groups and generators *who* are strategically positioned to serve the initial direct access customers, many perceive the dialogue on pooling as basically a delaying tactic. Utilities' and industrials' positions, are, however, closer together than may first appear. For example, the proposal of the last speaker is designed to handle just the first wave or two of direct access customers--only a limited number of customers. Many of them have large thermal loads and are already being served by co-generation. Thus, it's not clear that we're going to have a substantial number of direct access bilateral contracts to deal with under PG&E's proposal. While direct access by 1996 may appear on the first page of PG&E's proposal, all proposals voice concern at some point about controlling a direct access system. Some proposals envision what they call "additional institutions" to exert this control; in other proposals, it's called a pool. One way or another, there's a good chance that California will have a pool by the year 2000.

Another set of issues have to do with trust. First, can you trust the utilities? In talking recently to a group from the California Manufacturer's Association, it's absolutely clear that they simply do not. What we find in this debate is that all the old baggage from the regulatory wars is brought into the debate over Poolco versus Opco versus retail direct access. The current system has generated so much animosity that it is a potential obstacle to reform.

Another big issue is, can you trust the regulators? I think that's a far more serious issue. Utilities' first concern is whether public utility commissions are going to continue to honor the regulatory bargain. This issue boils down to how commissions will treat stranded investment. If utilities get any inkling from the public utilities commission that stranded investment is not going to be treated fairly from their perspective, then proposals for direct access will be shifted off into the indefinite future. If, on the other hand, there's some basis for trust, I think that that issue is going to be solved. It's my view that those costs that have been incurred on behalf of all customers and approved by the commission are going to be recovered through some sort of competitive transition charge or other mechanism. The essence of San Diego's proposal is that, if the PUC is willing to make such a commitment (and that's a big "T), the utility can put a pool in place and everyone will have direct access fairly quickly.

Another issue pertinent to regulatory trust has to do with the whole question of the Biannual Resource Planning Update (BRPU) proceedings. This is a centrally organized and mandated resource planning process that has been imposed on utilities. What this system basically does is to tell utilities how much to build, when to build it, and what ceiling price to put on it. Further, it imposes a bidding system that regulates resource acquisition to reach planned amounts using prescribed bidding procedures. The lesson from five years of experience working on the BRPU is that it doesn't work. In other states, bidding processes have gone forward with a great deal less regulatory oversight.

The main issue with which BRPU must now contend is the perception that some BRPU resources are priced significantly above the market. If utilities are moving into an even more competitive generation market, the last thing you want to do is to impose 15- or 20-year fixed price contracts that some perceive to be above-market. In response, utilities have basically done two things. First, they've gone back to the Public Utilities Commission as part of a legal strategy and said, "We want you to change that whole decision and throw it out." This, again, raises a question of regulatory trust. Everybody who relies on old contracts, the entire independent power community who are the winners of that process are saying, "Wait, that's six years of trust that you're just about to throw out if you do what utilities say." The second strategy that the utilities employ is to say, "All right, if you're going to force these contracts on us, at least give us the assurance in one of your decisions that the costs associated with those contracts are going to be passed through, that is, it's not going to be part of the competitive transition charge, 25% of which our own shareholders will have to meet." So far, the PUC has been stalling on that issue. Thus, we have a situation in which neither the generators nor the utilities are in the position to trust the Public Utilities Commission; that alone will hindering some solutions to the restructuring problem.

Three different processes are going on that help to sort out some of these issues. One is the formal hearings in front of the Public Utilities Commission. There have been four hearings attended by all five commissioners. Also, there are three different informal processes operating. Customer groups have initiated their own process, holding meetings in San Francisco. There's another group that involves at least 26 different parties, including the major utilities and some municipal utilities. Each is trying to figure out ways to deal with the new competitive environment. We probably need all three of these groups to tackle that one.

Discussion:

Several of today's speakers have contended that utilities can undertake some commitments during the transition, provided that regulators assure them that the costs will be passed through. One of the things that has been learned in the Northeast is that the regulator doesn't have the power any more to make such commitments. If the customers don't want to pay a charge, they won't. Many of them can self-generate, switch fuels, and/or intervene in the political process to prevent the pass-through. It's just not a realistic design for regulation, particularly in places where prices are high and there's a lot of competition. Many market models begin to fall apart when one realizes that fact, particularly proposals on preserving the benefits of integrated resource planning. If IRP is really desirable, then we shouldn't use the competitive model, because the competitive model just can't force consumers to pay for it.

: Alternative mechanisms to achieve some of IRP's goals could and should be explored. For example, regarding fuel diversity and fleet vehicle fuel economy, government minimum standards are currently applied to certain organizations. An analogous principle might be explored within the electric sector. One possibility would be to require any supplier participating in the market to have a certain minimum level of renewables.

Apart from the merits of the Poolco proposal itself, there is a question of whether those behind the proposal, namely, the utilities, can be trusted to design a fair system.

: All parties, including industrials, are welcome to join the group designing the Poolco proposal. Customers and regulators, as well as utilities, are responsible for the industry's difficulties today. None of these players should be disqualified from being a positive force in devising a solution. The pool model represents an evolution of an existing function rather than the creation of a new industry function. The United States has long had a pool-based electric industry; all that needs to be done is to make that pooling function independent of the utilities.

While the PG&E proposal has the disadvantage that it offers access more gradually, it is more a more minimalist approach and is hence less subject to manipulation by incumbent parties.

: How would the interests of small consumers be safeguarded in each of the market models? Small consumers are likely going to be represented by an "aggregator", who would bundle together a group of small consumers and find a supply for them. It's unrealistic to expect every residential customer to go out and sign his own independent supply contract with a generator.

A clearer separation of the goals of IRP and the mechanisms used to achieve it would be helpful. This also applies to **IRP, DSM,** incorporation of environmental externalities, and the social pricing for low income groups. Such an "unbundling" of goals and instruments might ease some people's concerns.

: The discussions and the models presented today focused entirely on the investor-owned utility sector. In the context of the California restructuring proposals, it shouldn't be overlooked that some 30-35% of the load within California is served by utilities that are not under the jurisdiction of the California Public Utilities Commission or any other state regulatory commission. There are municipal utilities, state agencies, irrigation districts, and federal power marketing agencies. Whatever market models get developed, one has to recognize a role for all of these entities to participate. Otherwise, you simply get a less efficient market.

Seminar Wrap-up

The morning's objective was to outline concretely some major shortcomings in the competitive wholesale market. The challenge that we have in front of us is first, to integrate some of the insights heard this morning and then, second, to try to segue from that to an alternative set of views about what some of the solutions might be. What we heard this afternoon is that trying to deal with some of the structural problems through divestiture of generation may not be the only option. There are some proposals being actively discussed that take a different approach to the problem, i.e., that try to understand just exactly how serious the problem is and attempt to articulate some options accordingly.

As for the afternoon's discussion, when one gets past the high-level rhetorical discussion to start talking about how to actually implement a proposal, one must confront myriad operational details. It is likely that many of the problems that must be confronted turn out to be the same no matter which model you start from and that there are relatively few choices that are available if all of the criteria commonly raised in the California discussion are to be imposed. I hope that the debate could transcend the rhetoric and get down to operational questions. Much disagreement tends to vanish as people discuss these issues in more depth. At the same time, however, the time pressure is enormous: The decision process that the California Commission is going through is wrestling with the political debate that we heard about today. At the moment, we have a lot of utilities who have stepped up to the plate, made different proposals, and embraced the ideas of greater competition and direct access. If they perceive that they'll be shortchanged in the process, they're going to change their mind; there are lots of opportunities to put sand in the gears. It is essential to take advantage of the willingness to proceed at the moment, find something that's actually going to work, and do it. Our discussions here are having some impact in this direction; many of us are involved in similar deliberations elsewhere. The opportunity for change in California is particularly important. If the California reforms go sour, it is going to set things back across the rest of the country. Thank you all for your participation in this important discussion today.

Handouts for 9/23/94 Harvard Electricity Policy Group Special Seminar

Some of the materials listed below were prepared specifically for the seminar. Please do not cite any materials marked 'Draft. "

- Ballance, John W. *Competitive Market Structures in Electricity.* Draft, September 23, 1994.
- Garber, Don, William W. Hogan, and Larry Ruff. *An Efficient Electricity Market.• Using a Pool to Support Real Competition.* Electricity Journal 7(7), September 1994.
- Hogan, William W. *A Competitive Electricity Market Model.* Draft, September 5, 1994.
- Kuga, Roy. *Direct Access: PG&E's Proposal to Begin Implementation.* Draft presentation, September 23, 1994.
- National Independent Energy Producers (NIEP). *Is Competition Here? A Preliminary Evaluation of Defects in the Market for Generation.* Draft, September 21, 1994.
- Pacific Gas and Electric Company. *Direct Access. The First Three Years.* "Working Draft" handout, September 13, 1994.
- Pierce, Richard J. ***The Importance** of De-integrating the Electricity Industry.* Draft, August 11, 1994.
- Sant, Roger W., and Roger F. Naill. *Let's Make Electricity Generation Competitive.* Draft, June 23, 1994.
- Skilling, Jeffrey. ***The California Industry Restructuring Process.*** Draft presentation, September 23, 1994.