

**HARVARD ELECTRICITY POLICY GROUP
MARKET OPERATIONS SEMINAR**

**Bell Hall, Kennedy School of Government
Harvard University
Tuesday, November 30, 1993**

MEETING SUMMARY¹

1 WELCOME AND INTRODUCTION

After welcoming the seminar participants, Professor William Hogan noted that the topic of today's seminar, the nature and operation of the electricity market, has arisen repeatedly in the context of the Group's other discussions on stranded assets and jurisdictional questions. In particular, as elaborated in the papers to be presented today, the operation of the short-term cash market and the associated longer-term implications will constitute the major focus of this meeting.

¹Steve Anderson/KSG served as rapporteur for the Seminar. This report attempts to provide brief overviews of the presentations given and to capture the main points made in discussions following each presentation. Some contributions have been rearranged to enhance topical continuity. Finally, no individual participant is responsible for the ideas presented.

As a vehicle for understanding market operations on the electric side, it is clear that valuable information can be gleaned from the experience of the gas industry. The similarity of problems, trends, and transitions seen in the two industries has already been noted in several of the Group's meetings. Many observers view the evolution of the gas industry as a model for transition within the electricity industry. The question which the Group is attempting to address today is the extent to which this analogy holds, ie, where limitations to this analogy might exist.

One perspective, which may be characterized as the "electricity is different" perspective, emphasizes the unique characteristics of the electricity system: the interconnected high voltage *transmission grid*, the problems of *network interactions*, *loop flow*, *stability control*, *central dispatch*, and so on. The argument from this perspective is that, particularly in the short run, the physical characteristics of electricity are different enough that something else has to be done in order to operate that system effectively. The other perspective is that "natural gas is the same." This is not to say that electricity is simple: it just says that natural gas isn't so simple. This perspective would assert that the arguments that natural gas is different because it's technically simpler are invalid; many of the problems that one encounters on the electricity side are encountered on the natural gas side, as well. This argument holds that solutions to these problems in the natural gas industry have been devised which allow for competitive access and a competitive market; if one would adapt these to the electricity system, everything would work well.

These are simply different views of the world. Which one is right is still an open question -- the Group will explore this dichotomy in this meeting. Obviously, if the second view is correct, then there is a great deal to be learned about all aspects of the gas industry - lessons beyond the overarching transitional or structural issues on the specifics of how to operate the market. These analogies would be a rich source of information and experience in designing a framework for bilateral trading, in particular, in the electricity market. If the former view is correct, then something else is going to be required in the case of electricity; the question, then, is: What is that and how does one go about doing it?

In closing, Hogan suggested the following ground rule. Frequently, in meetings such as this one, economists (and other professionals) will make assertions along the lines of "Well, we ought have a competitive market and we can work out the details. The details are not critical for being able to operate this competitive market." (In a certain sense, Congress did this when it passed the Energy Policy Act which says, in effect, "Provide open access to the transmission system and do well, and work out the details.") The Group should be critical about accepting such assertions as a legitimate defense of a proposal. If someone suggests that there are complications in a proposal at hand, the Group ought to be trying to think hard about what fundamental complications are likely to be encountered, rather than just dismissing such objections out of hand. In order to get to where the two different views of the world sketched above might conflict, one has to get down to details. Many participants in this Seminar are very knowledgeable about the details, about how these markets operate and about the commercial perspective on how the system can work.

Collectively, the Group should try to come to a better understanding of what's possible and what is feasible in real-world markets.

2 SETTING THE CONTEXT

2.1 GAS INDUSTRY EVOLUTION

Paper: *Gas Industry Evolution*

Speaker:

In the unbundling of the natural gas industry occasioned by FERC Order 436, the following concerns were commonplace:

- Lack of familiarity of market participants with new roles and responsibilities;
Zero-sum game: competitive supply access will almost certainly be at the expense of others;
- False savings, as transportation volumes would only displace pipeline sales volumes, resulting in significant take-or-pay costs and liabilities for the pipeline and ultimately, the consumer;
- Increased costs to customers who remained with the pipeline merchant service;
- Protections required to ensure that the pipeline can continue to meet existing sales obligations;
- System reliability and continued service of the public interest.

The table below summarizes salient problems associated with the implementation of Order 636 -- the final step in the unbundling process -- and the solutions which have been developed by the natural gas industry in response.

PROBLEMS	SOLUTIONS
General supply area administration	Creation of pooling points (aggregation)
Firm capacity entitlement in supply area	Capacity allocation and/or capacity delegation
Grid-type pipelines vs. long-line pipelines	Iterative nomination/capacity allocation process
Balancing services	Minimize monthly imbalances; Daily confirmation and allocation
Managing "swing" or daily variance from scheduled volumes	No-notice transportation service
Managing upsets or emergency conditions	Operational flow/control orders
Determining value of the gas commodity at various locations	Henry Hub/gas futures market
Information availability	Enhancement of electronic measurement and information communication via the pipeline's electronic bulletin board

Discussion:

One participant offered the characterization that many issues in an inter-industry comparison of electricity and gas are "the same, but different." The natural gas industry is more market-oriented than the electric industry with respect to access, commodity markets, and trading institutions. In contrast, the electric industry is much further advanced in its ability to trade on a short-term basis and on its inter-system reliability. In gas markets, a

very strong intracorporate orientation has evolved because of natural gas husbanding that occurred in the '70s and early '80s.

The issues of *stability, network interactions, and multiple constraints* are present in gas just as in electricity. As a matter of fact, the tradition in the gas industry was to solve a lot of inter-pipeline issues by gentleman's agreements. Tariffs would be filed at FERC, but the agreements were to exchange the gas and to make up for it eventually: it was all just part of a comfortable club arrangement, where transactions would eventually be balanced out. That has a very similar ring in the electric industry. There was no centralized dispatch on the gas side -- again, a very intracorporate orientation.

The *short-term market* in gas has evolved from what was originally, in essence, a monthly market with a best-efforts commitment. Once the marketers and the arbitragers got into the business of best-efforts commitments, gas simply went to the person paying the highest price. That is evolving now through a weekly market, a daily market, and, within the next year or so, one might expect that reasonably well-functioning hourly markets will exist, where the commitments are firm and highly reliable. These markets will be backed up by storage facilities to make sure that the proper balancing is taking place. With secondary markets and the evolving electronic trading systems, which facilitate short-term trades in both pipeline capacity and the commodity, the bilateral secondary market has worked, but there is no reason to believe that that is the best way to operate the gas industry. It is not clear that some kind of central market mechanism in regions couldn't enhance the performance of the bilateral market.

Point to point service is interesting, because the gas industry's experience evolved away from point to point transit. Customers recognized that under point to point transportation they couldn't get the firm peaking supplies they desired. The system evolved to a system of reliance on a smaller number of firm receipt and delivery points. Aggregation takes place at these critical points, and capacity right is the right to reach one of these locations. There are also secondary receipt and delivery points, which means that anything inside of your path or inside some general path can be traded. Network service, when it is finally established, is going to look somewhat similar. There will be primary receipt and delivery points that are highly reliable, and secondary receipt and delivery points that will be available only if the operator can demonstrate that there's a capacity constraint.

Pooling versus hubs. On the gas side, resources can be pooled on an intrasystem basis. Hubs extend that concept to an intersystem basis. The accompanying rate design for hubs has not yet been fully developed; trading in the hub is still a somewhat frustrating experience. It's not clear whether hubs have a good analogy in the electric area. Hubs make the commodity market deeper. If there are many transactions taking place at different receipt and delivery points and the markets get very thin, the players in the markets start to get suspicious that people maybe be manipulating the market. With multiple pipelines, multiple traders, and a hub operator who is not a player in the market, traders develop more confidence and the market gets deeper. At Henry Hub, this confidence was actually reflected in prices somewhat higher than at some downstream points

Electronic bulletin board systems, production area rate design, gathering, are all issues that are going to have to be settled on an *intersystem* basis. Transco would not go forward with a production area rate design unless the production area rates of the other systems were designed in coordination. Such issues are going to have to be settled on an intersystem basis, not an intrasystem basis. One can't solve those problems in a rate case context; consequently, one might expect more regional conferences and regional solutions. RTGs come to mind as a way to deal with these regional issues. The *electronic bulletin board* construct can facilitate such coordination on a national basis.

Month-end *cash out programs*, which allow pipeline companies to minimize their risks from price swings, were an attempt to be even-handed. Under these programs, however, the monthly market tends to be usurped by a weekly or daily market and the arbitragers start pushing gas into the system or withdrawing it, based on the cash out arbitrage opportunity.

Some degree of *centralized market authority*, at least on a regional basis in the gas industry, might well make a lot of sense, especially to improve conditions left over from bilateral trading. It's not clear at all that bilateral trading is the most efficient way to do business. Given the fact that gas transport has its own complexities and has had structure and stability problems, some degree of centralization, especially in the short term with respect to market centers, may improve the operation of the market.

A remarkable characteristic of the electricity market is that there is *no visible price*. One could ask pool members or brokers for certain information, and then perhaps compute prices. It's all club-oriented, however, and there's no publicly available price information. Especially for large systems run by one company, public information is very sparse. In a sense, the electric industry trades blind, but trades well and fast. On the gas side, one gets a great deal of price information, but it's all very speculative and does not represent actual trades. In theory, self-interest should prevent people from reporting their prices to the trade press, but in fact, people seem to do it and the result is accepted as reliable information.

If a pipeline is in danger of not being able to operate, it has the right and the ability to implement operational flow orders to require suppliers to bring gas in where needed in the system. It is unclear how often such orders will be necessary, as insufficient experience with the unbundled operation of grid pipelines has been gathered to date.

Two methodologies exist for pricing gas injection. The first is that a party has contractual rights to storage on the system, and they inject their own gas. Another option proposed by some pipelines are what is called SBA providers - system balancing arrangements. These parties, as needed, will inject gas into the system for a fee. The gas will be returned to that party at a later date, so it's simply an out-of-phase balancing arrangement. SBA costs are covered by rates, which are adjusted in subsequent rate cases to account for actual SBA services provided. The operational flow order system will evolve. Most industry efforts in the wake of Order 636 concentrated on technical quantity issues

rather than pricing questions.

A participant asked about the importance of maintaining pressure in the pipeline to avoid system collapse (analogous to the maintenance of voltage levels in the electric system). It was stated that the system can collapse, but only over a relatively long period of time. For example, it took about three days of extremely cold weather in the market area in December of 1989 for the gas pipeline business to be critically affected. Since then, producers have modified their production control systems so that they're not dependent on one another, and put in electronic flow meters at critical points. When pipeline pressure starts to drop, the first step is, naturally, to shut off any injection into storage. Then, as necessary, one can reverse that and make a withdrawal from storage. In general, operational decisions on the electric side are facilitated by the availability of a large amount of information on the status of the system. Gas lags behind on this score.

2.2 PROBLEMS IN POOLS

Outline: *Problems in Pools (As Illustrated by the U.K. Model)*

Speaker:

Many similarities exist between the pool approach and the bilateral market approach. Proponents of each are both talking in terms of open access, and advocating unbundling and trading in capacity rights. The fundamental difference revolves around the question of how the market is going to be structured and run. Is it going to be run out of the physical

market overseen by a central control group (which is not the experience in the natural gas business), or is it going to be based essentially on bilateral transactions?

A pool approach with a bidding system is not going to allow the parties to capture all of the efficiencies that they would in bilateral negotiations. Some examples of the efficiencies inherent in bilateral transactions follow.

- In a pool, bids are essentially one-dimensional: They are made in terms of price only. Other terms, (eg, delivery terms) have to be standardized, and hence do not allow for creativity or provide much information on cost structures.
- Efficiencies can be captured through discussions between participants in the business who understand how the gas market works, discussions not only on commodity cost, but also on transmission costs and the alternate use of transmission rights that may be available to those who are negotiating the transactions.
- Negotiations in the gas market, especially in medium to longer-term arrangements, often focus on force majeure positions. The continuum of reliability and of supply arrangements is recognized; this gets captured in the contracts.
- Another example of heterogeneity would be credit differences. In some cases, companies are able to get a better price because they may have better credit compared to their competitors.

- On the demand side, there's a significant difference between having a single, utility-run demand-side management program and having one that is tailored very specifically to the demand profiles of each individual customer.
- Some "intangible" contributions to the efficiency of bilateral transactions: the understanding of operations and the transactional expertise that comes from being a physical player in the short-term spot market, cultural and institutional differences between natural monopolists regulated by someone running a poolco or a gridco and the customer-responsive entrepreneurs that would populate a more bilateral, decentralized approach.

Discussion:

Traditionally, reliability has been a primary motivation behind the use of pools. In the UK, reliability is the main reason for having a centralized grid system. It would not be feasible to have many people making bilateral contracts when you have a constrained system. Still, as part of a pool, one does have bilateral transactions with the companies outside of the pool and limited bilateral deals within the pool itself. Such deals do not, however, undermine the general principle of centralized unit commitment and centralized dispatch, which allow pools to dispatch at the lowest incremental cost. In addition, load following is much easier for a pool than for a single utility.

One participant commented that the electric industry might not ultimately choose between bilateral and central market structures: there are fundamental elements of both

approaches found in the gas industry, for example. In the electricity grid in New England, to take another example, many bilateral transactions are taking place which are overlaid by the nuances of price and risk. The New England Power Pool (NEPOOL) basically sets the ground rules for transactions by stipulating that trades may only be done so as not to violate some reliability rule.

For clarification, NEPOOL doesn't really intervene in many of the transactions. They just take information as it is received on what people want to generate here and generate there without looking at the incremental cost of doing those kinds of things. They just take nominations for these bilateral transactions. They may say no sometimes because the system will become unstable if they didn't, but there's no central control that says it's cheaper to run this plant than that plant in this 15 minutes.

2.3 PROBLEMS IN BILATERAL MARKETS

Outline: *Market Structure and Transmission Puzzles*

Speaker.•

The speaker sought to draw distinctions, where possible, between central market trading (CMT) mechanisms and bilateral trading (BT) mechanisms and to suggest which of the two mechanisms would have a comparative advantage in addressing a variety of thorny issues in electricity transmission. First, under CMT, the pool coordinator must know the structure of the grid, and in particular, where the constraints are. The BT mechanism incorporates no central market coordinator. Second, CMT schemes have well-defined

capacity rights. In a BT market, capacity rights would be reasonably clear, but perhaps not so well-defined that curtailment would always be prevented. In general, many of the problems that arise in bilateral trading are avoided in the central market model.

These two alternative market structures can have very different capabilities in addressing transmission questions, as illustrated below. Note that only in the first two rows of the table are the distinctions due to *market structure* exclusively; in the rest of the table, the distinctions arise due to differences in defining *capacity rights*:

	Central Market Trading Well-defined capacity rights	Bilateral Trading / Current capacity rights
Network transmission services	No problem, given a single system dispatcher who knows the grid	Requires some discipline superimposed on network service, as no single trader is monitoring overall grid constraints
Opportunity cost pricing for firm transmission service	Little scope or need for creating capacity through operational changes	Operational changes create transmission capacity more cheaply than construction of new capacity
Pricing loop flow	Payments for capacity rights	Flow-based pricing, but not attractive to all
Priority of service, native load vs. third parties	Everybody has same rights	Utilities will attempt to maintain native load advantage concerning access and curtailments
Incentive of grid owner to overbuild	Customers forecast own load and purchase appropriate capacity rights - - lessens incentive to overbuild	Regulatory discipline required to prevent overbuilding
"Vacuum-cleaner" and "extension-cord" transmission lines	Customers have incentive to build correctly	Oversized lines can claim parallel-path compensation; have-nots build undersized lines to gain access

In closing, problems that appear to be aggravated by CMT include

- How to create capacity rights in the first place? In the gas pipeline grid, it's not straightforward, as mentioned earlier today.
- How will costs be recovered, based on those rights?
- Pursuit of efficiencies would appear to be less aggressive under CMT, with only one dispatcher as opposed to many independent operators thinking about the unit commitment and dispatch problems.

Discussion:

It was argued that pools and bilateral sales are not mutually exclusive. Instead of a binary choice, one should focus on just how much one should lean on one foot or the other. Pools, in part, developed as a response to the original chaos of the two party bilateral trading world that existed in electricity.

Recently, one has seen an increase in both internal and external two party sales in New York State, causing a bit of consternation and worry to some. The interesting question is why there has been an increase in two party sales. Two reasons were cited:

- Shared savings pricing. (Where the trades capture arbitrage around the
- pricing rules)
- Incentive regulation may be increasing the propensity of companies to explore the possibility of economic gains from two party sales.

There's an important distinction to be made between internal and external two party sales.

Internal sales, such as the recent ConEd-NiMo deal, don't affect dispatch. External sales, in contrast, can have a deleterious effect, at least under current dispatch procedures.

Another distinction to keep in mind, another participant argued, is that the West is different from the rest of the U.S. The western electric grid looks more like a gas pipeline system than it does like the grid in the northeast United States. The attractiveness of RTGs and Steve Walton's arguments about capacity rights have a lot to do with the linearity of the system. In contrast, it is more difficult to see how capacity rights might work in New England. Furthermore, it was pointed out, capacity rights must be defined sufficiently flexibly, because seasonal variations in system loading will change transfer capabilities with the season, as well. Finally, the size of RTGs matters. On the one hand, in some regions of the country, there are many small control areas which could benefit from trading with each other more efficiently, eg, by forming a single RTG. On the other, making such a group bigger and bigger just makes it tougher to get agreement.

Fragmentation is manifested differently in the electric industry than in the gas industry. The electrical network is physically different, tending to extend radially outward from a central point. The gas system, in contrast, tends to have long parallel elements.

Institutionally, the electric side suffers from greater fragmentation. On the gas side, there's enough jurisdiction at the federal level to try to deal with issues such as potential stranded investment from the take-or-pay contracts of interstate pipelines. In electricity,

most of the assets that people feel are economically threatened are regulated not by FERC but by the states. Thus, there's a different concentration of jurisdiction which creates a different set of issues and a different set of incentives in the two industries.

One participant suggested that the problem of potentially stranded assets needed to be addressed as well in the context of the discussion on central versus bilateral transactions. It was argued that this was indeed a big issue, perhaps the most critical transition question. One certainly wouldn't want to define transmission access or capacity rights in a way which would preclude dealing with the stranded asset problem or force one to deal with it in a particular way. It would, however, burden the discussion of cash market operations excessively to take this question explicitly into account. The question is being pursued by the HEPG through other processes.

Another participant argued that capacity can indeed be defined. It is not fixed, yet, reasonably defined, one can use pro-rata mechanisms to share curtailments as capacity changes. The important issue is how it is valued and used after it is defined. Another suggested that capacity could be defined with a fixed number.

3 ALTERNATIVE MODELS

3.1 GAS MARKET MODEL

Outline: *Bilateral Neogtiation Model of the Electric Utility Industry*

Speaker:

It is important to address three basic issues in deciding whether to emphasize the perspective in the debate on transition in the electric industry:

- The goal of the transition process
- Which perspective is more convincing: "Electricity is Similar" or "Electricity is Different"?
- Which model allows for gradual implementation to facilitate learning by doing?

The fundamental difference between what has developed in the gas industry and the "Pool Market Model" to be presented later this afternoon is the nature of the dispatching mechanism: bilateral transactions versus a regulated pool. The speaker argued that although *operating* efficiency gains might be available from a centralized, regulated pool, these are more than offset by the *commercial* efficiency losses associated with the failure to allow market participants to define the terms and conditions of the cash market through bilateral transactions. Hence, it was suggested that the greater efficiency achieved by opening up the market to more buyers and sellers under the bilateral model ought to be the overarching goal in the transition.

The frequently cited "differences" between electricity and gas in 1) the time scale in which system operating conditions change and 2) the frequency and significance of loop flow problems, it was argued, are often overrated. As for timing, disturbances in the electric grid clearly travel faster, but the tools for dealing with disturbances are also faster acting than the means for regulating gas flows. One difference, the greater availability of real time data on the electric side, may in fact facilitate the transition to open access. In the electricity industry, loop flow is often talked about, but, it was argued, little quantitative analysis of the problem exists.

Over the decade 1983-1993, a set of increasingly complex nomination, scheduling, and capacity allocation procedures has evolved within the gas industry to address congestion problems. Without allowing a similar heuristic learning process to unfold on the electric side, one will never know if bilateral negotiation couldn't have solved the operational problems foreseen today. For example, one could envision third parties owning and operating peaking units to help stabilize the system. There would be potentially hundreds of entrepreneurs coming up with ways to shed load in ways that the utilities may never have thought about, and doing it in ways that're economically advantageous for these entrepreneurs.

Discussion:

It was mentioned that, in fact, the electric industry started some 25 years ago creating what's been described here as a "tight pool." The speaker's description of the gas industry

sounded very much like the New England Power Pool. It would appear that the tight pools come close to the bilateral model just presented. In **NEPOOL**, there's hardly a power plant being built by a utility; there's a highly competitive wholesale market out there now. Since the pool is fundamentally a pool of customers (including distribution companies), not a pool of utility power producers, the focus ought to be on the customer. The decisions on how to provide needed capacity and more generally, how to address IRP are individual customer decisions.

Transmission does in some sense operate on a dispatch system. Dispatchers pay no attention to company boundaries -- they operate the system as if it were a unitary whole. After the fact, they sort out the money; this "dispatch now, settle later" process works well.

For on-demand gas which is supplied to meet load variation, there's a reasonably efficient market, absent locational differences or capacity constraints. There's a price discovery process of buyers and sellers bidding and negotiating with one another.

Other differences between the electricity and gas industries were raised. The short run marginal production cost of gas flowing from one well or another to meet a given demand is about the same. The marginal cost of meeting electric demand can vary tremendously, depending on whether one burns gas, coal or oil. Hence, there is a greater potential for gains from trade on the electric side. That's the reasoning behind central dispatch, to make sure that the gas unit is run last, the oil unit next, and the coal unit as the

baseload plant. One doesn't have to worry about this merit order in the gas industry, except in very broad terms. That's why electric power pools were created, to do this optimization and perform centralized dispatch. Secondly, the time factor is important not only in a physical sense, but the rate of change of price. Which units are running changes not only every day, but all during the day, in reaction to changes in market price. Thirdly, the capacity in the electric market depends on which units are running. That, in turn, depends on what the price is. The system can always move more electricity from one point to another if it is willing to incur some out-of-merit generation cost somewhere else. So again, there are differences in the cost of generating electricity in different plants at any given time.

Some participants were dubious that gas producers would agree with that characterization. Rather than a cost based system of determining which units are on, a bilateral negotiation process generates the market price. The question often arises how capacity is going to be allocated in various places because of differences in wellhead prices. It was observed, however, that price swings on the electric side, however, which can range up to 200 - 300 %, greatly exceed such variations on the gas side. Bilateral contracts couldn't be written fast enough to serve as the basis for electric system operation.

Another participant objected that this notion of operating the system was wedded to the concept of centralized dispatch where the set of buyers and sellers was much more limited than it will be in the future. The essential benefit of open access transmission is that

it allows a broader array of buyers and sellers. One ought not use the old integrated model to design a new market system; the industry will not develop a market-based system if the notion of cost-based dispatch rather than negotiation-based dispatch (within the constraints of reliability and congestion) is taken as given. Recall that these are exactly the same arguments heard in the gas industry for years as to why the system shouldn't be unbundled. Yet, after the fact, the efficiency gain of operating an unbundled system has been significant.

Another participant suggested that unbundling was not at issue; this should take place in any case. The question is, what's the right market mechanism that will unbundle the system while keeping the lights on?

An historical perspective was offered on the development of the electricity market versus the gas market. In the electricity industry, pools formed in part to address reliability concerns. Pools recognized that bilateral exchanges, at least in New York, were causing some fairly significant problems in terms of system-wide dispatch. In response, economic dispatch was developed. With economic dispatch in place, operators themselves concentrated on transmission problems and security concerns. In the gas industry, it seems that there were none of those pressures because the reliability issue wasn't as acute.

A question was raised as to the order of magnitude of the efficiency gains to be expected as a result of restructuring. One participant recalled that FERC indicated in a letter to Congressman Sharp that, while any calculation of benefits is highly speculative, it

is believed that the benefits of restructuring are there. A follow-up question concerned possible post-restructuring benchmarks in the gas industry which indicate benefits that are, if not precisely quantifiable, generally viewed as sufficiently "large" to justify restructuring. Three such benchmarks were cited. First, in the interstate power market, no independent power projects built with gas were undertaken until it was possible, after restructuring, to contract separately for gas. This innovation represented a substantial efficiency gain for the economy as a whole, given the advancements in combined cycle technology. Second, prior to restructuring, excess capacity was held by customers and not released into the market because there were no incentives to do so, and no mechanism for firm transportation. Third, in the absence of a short-term mechanism to set spot prices, there was no price discovery process, no futures market, and hence no system for financial risk management.

One participant characterized the debate in the seminar at this point as centering on the questions of 1) the mechanism that decides which units operate -- ie, a centralized cash market or deals between individual market participants, and (under the bilateral mechanism) 2) the severity of the constraints on market participants' actions which may be necessary to ensure system integrity.

31 POOL MARKET MODEL

Outline: *A Competitive Electricity Market Model*

Speaker.

It is important to be clear on the extent to which electrical energy may be treated as a commodity, in other words, as a homogeneous product with essentially two dimensions to it: basically a *megawatt* over a half hour that's provided *in some location*. It may cost something different to generate from different plants, but once produced it's the same thing, meaning that any megawatt at a particular location is a perfect substitute for any other. Part of the argument in support of bilateral trading, however, is the assertion that in the very short run, megawatts are not perfectly substitutable. Hence, bilateral trades are considered necessary to realize efficiency gains from trade across diverse products. The central market solution, in contrast, says that once produced, a megawatt is a megawatt within a given half hour, and gains from trade are best achieved through a centralized market.

Ignoring transmission constraints for the moment, electric plants in a pool are dispatched in the usual merit order, from cheapest to most expensive. Given enough time in this simplified world, bilateral trading and a central dispatching pool would achieve the same result. The difference in power pools is in the determination of the price. In NEPOOL and other tight power pools in the U.S., payment is through split savings.

The resulting price for everyone, on average, is equal to average cost. Under this

system, there's no contribution to capital costs. In the British system, a market clearing price is calculated every half hour. When the price is low, generators just cover their fuel costs; when it's high, there's a margin which would go toward covering capital costs.

The notion of reliability in the British system is not the conventional one: under this stylized marginal cost pricing system, each consumer has completely reliable service for the amount which they demand. One observes fluctuations of price (which naturally affect demand), not fluctuations of availability. Thus, customers' decision is no longer framed by a quantity question, but by a price question.

The bilateral contracts in the British system between buyer and seller set a reference price for power; deviations from this price in the pool are compensated accordingly. hence dispatch operations are separated from long-term price guarantees. The U.K. model ignores network interactions and transmission constraints. Taking these factors into account requires definition of transmission capacity, which as several speakers have noted, depends on the pattern of loading within the system. Conceptually, the problem of transmission congestion is ubiquitous, but the magnitude of this problem is unclear.

Efficient pricing of transmission capacity is known in the trade as "Schweppe" spot pricing, after the late Professor Fred Schweppe. Every location in the system has its own Schweppe spot price, the market-clearing price. These prices will reflect both the effects of losses in the system and the effects of transmission congestion. The great attraction of

this transmission pricing scheme is that all of the short-run complications of loop flow and network interactions are embedded in these prices.

The key question in defining capacity and transmission rights is the feasibility of actually dispatching the system the way the rights are configured. Once a configuration that is viable in engineering terms is decided upon, capacity rights may be interpreted as the right to collect congestion rentals between two points on the system for a given capacity. An important property of this scheme is that the local prices which people face are just high enough to provide the pool enough revenue to make the appropriate congestion rental payments to owners of capacity rights.

Proponents of the bilateral model are right to ask about the efficiency of the grid operator. In earlier studies of this issue, operators did receive high marks for efficiency. Still, these studies are rather dated; it's unclear if they still apply today. Under the proposed central pool model, operators will certainly have many parties clamoring for them to do things differently, as everybody on the congested side of the system without long-term transmission contracts is paying very high (marginal-cost) prices. They will be beating down the door of the dispatchers, wanting the system to be run differently, additional transmission to be built, or capacity rights to be reallocated.

New products and services would certainly develop under the pool market model. In England today, for example, to complement the spot market, there are a variety of

financial services, eg, hedging and price stabilization mechanisms, available to electricity consumers. There are new businesses that try to predict when the business peak is going to be so that producers can ensure that their generating plants are available at that time.

Discussion:

It was asked how problems of local market power (ie, being able to influence electricity prices by withholding generating capacity) were addressed in the pool market model. It was argued that, on the one hand, *bona fide* market power and on the other, situations in which a relatively low cost producer is located in a constrained region must be distinguished. When it is difficult to transmit power into a region, such a producer should not be paid its own low cost; it should receive a high price due to the congestion. *Bona fide* market power would be a situation where, for example, 100 MW could be generated but only 70 MW are offered because the generator can drive up the price more than proportionally. The pool market model does not solve this problem. The relevant question is then, does this system do better or worse in dealing with this problem than competing alternative models for dealing with market power? The British system, for example, does not deal well with this issue at all.

The next question concerned recovery of capital costs for generating plant. A market mechanism is at work here, as well. Generators can share their risks, since they can sign price-differences contracts with customers. In addition, they might capture some additional

fixed charge payment. Basically, new capacity gets built when some mix of the customers and generators expect that future congestion rentals collected by this generation plus the avoided rentals paid on the demand side will be large enough to justify the cost of new capacity. As a real-world example, a recent proposal in New Zealand to the Commerce Commission said exactly this, namely, that no new investment or major upgrades in the system will take place without customers agreeing in advance to pay the hiked charges. This is a very attractive property, which avoids, among other things, the problems of ex post prudence reviews.

The optimal bids on the part of generators in the pool dispatch scheme would be each generator's own *marginal cost*. In settling accounts with the successful bidders, however, each is paid the *market clearing price*. If a generator is paid only the market-clearing price, one participant commented, the side contracts for differences between the generator and the buyer are an important part of the decision calculus of market participants.

It was pointed out that if a transmission facility is duplicated by a new entry into the marketplace, congestion rentals would go to zero. The people who benefit from the new line are the people who built it and those who are in the spot market who don't have capacity rights or a free routing. People who have current transmission capacity rights aren't affected by such a change. If one obtains some capacity rights now in order to reach a distant market, and another party later builds another transmission line to the same market,

it turns out that the original didn't have to be built because the new one is adequate for both parties. The first can free-ride on the second. In that sense, the first builder might regret having put the investment in place to obtain the capacity rights. This is identical to the scenario where an expensive power plant is built in an area because it's predicted that it will be cheaper than future alternatives. Sometimes such projections are simply wrong! If the builder of the first was wrong, the new power plant next door doesn't cost any more because of the error. Of course, the builder of the first plant is worse off than if he'd been lucky.

In today's transmission market, the problem is that it might turn out that somebody might take some action which makes it much more expensive for existing plant owners to run their power plants. If transmission capacity rights aren't defined, one could end up in situations where the cost of getting power out to market is much higher than ever expected because of congestion in the system.

One can't guarantee specific performance with the grid, ie, a contract to move power from A to B. One *can* guarantee the economic equivalent, however, which is what the pool market model attempts to do with transmission capacity rights. With such a transmission right, one can always buy the power from A and in effect transmit it to B for the price of losses between the two points, without worrying about the congestion rentals. This is true whether or not any power actually moves from A to B. A risk-taking third party, C, may not have capacity rights. If the system is congested because of C's demand, C is going to pay

a lot to the pool. The pool will pay the rental to A and B, the capacity rights holders, to make the economics of their deal the same. At the margin, B will be paying the same thing that C is if B buys incrementally more or less, but for the amount of capacity rights owned, B will just collect congestion rentals from the pool.

The reason such transactions can't be done bilaterally is because the trading ratios are two-for-one here, four-for-one there, and three-for-one somewhere else: these proportions change every half-hour because of loop flow and the associated network interactions. The question of who's going to be paying how much congestion rental to whom can only be figured out during that half hour. The capacity rights which people own, however, are well-defined, fixed and do not change unless the owner negotiates another deal.

Ignoring transaction costs, the optimal system would always be slightly congested; if not, then almost by definition, too big a transmission system has been built. (The exception would be a very lumpy transmission expansion.) If a situation arises in which it's very hard to build transmission, congestion may be great because new transmission is difficult to site these days.

It was asked if generators would be paid for maintaining spinning reserve. Spinning reserve is straightforward to accommodate in this model. It is incorporated in transmission prices, keeping locations differentiated.

4 GENERAL DISCUSSION

One very rough benchmark for the seriousness of the transmission congestion problem was cited in which 100 hours worth of calculations were performed and then the proportions of time that the system was in various conditions were determined. Based on this simulation, a required revenue figure was calculated, ie, how much capacity rights owners would need to recover. The congestion accounted for about 40-50 % of required revenues, a large sum of money.

Given economies of scale, the following two conditions could prevail simultaneously: 1) congestion rentals are large in terms of the exposure that people face (which they can protect themselves against with capacity rights), and 2) these rentals are small compared to the cost of building a new line. The only thing that has to be true for the line is that the congestion rentals *but for the line* have to be large. If the line is built, it costs so much that congestion rentals fall to half of the cost of building the line. Still, that half is a big number if one is still going to be exposed: one doesn't want to build the line and then still have to pay the greater congestion rentals.

Under the pool market model, the speaker asserted that there isn't enough time for central dispatch to inform people about bilateral trades. A participant argued that bilateral trades could be discovered and executed by the two participants, without the intervention of the central market. Why couldn't these take place? The centralized market, it was argued, is precluding bilateral trading in the physical commodity, while bilateral financial

transactions in secondary markets are not precluded. Furthermore, some participants questioned the conventional assumption in the electric sector that central dispatch offers greater economies than a strategy of letting individual plants choose when to run.

Another argued that it is entirely possible to have efficient system operation with parties conducting competitively motivated bilateral trades in a system which has central control of the half hourly dispatch process. The key is to get the pricing right at all locations. The one complication on the electric side is that when one knows what the price is at Henry Hub (a node of a transmission system, say), it's not obvious what the price is in New York. Some additional calculations are needed, which the pool could perform. To characterize the model which will be presented in the afternoon, one may think of complete centralized control over 15 minutes or half an hour and complete decentralized bilateral transactions for everything else in terms of price hedging, nominations and available capacity. Another participant pointed out that this model greatly resembled NEPOOL, where there are hourly bilateral and hourly interrupt bilateral transactions (previously weekly and daily). On the 15 minute basis, the pool makes the decisions by sending out signals to generators to turn on and off, which determines the economy business in that time frame.

One participant suggested that an instructive analogy can be found in the gas industry's experience with unbundling. When confronted with demands for unbundling of their services, pipeline owners objected, arguing instead that the status quo was indeed

efficient: The pipelines took bids from producers, purchased the cheapest gas that meets demand, bundled their services together, and optimized their flows and storage. Customers got just what they wanted. In terms of pipeline operation alone, the producers were right. Looking beyond the relatively narrow question of operational efficiency of the pipeline to consider the efficiency of the gas market as a whole, however, there's a good case that the new products and services which were "invented" and offered by entrepreneurs on an unbundled basis bring with them substantial welfare gains. In the electric sector, one would expect that offering, say, spinning reserve as a separate, unbundled service would place the provision of this service on a more competitive basis. It would allow entrepreneurs to build smarter mousetraps. To return to the pipeline example, the pipeline operator and the "unbundlers" disagree because they're optimizing different things.

Applying the bilateral trading model to a system with congestion and network interactions would be problematic, because trading loads between different points in the system needs to be done in accordance with relative impacts or constraints existing between system nodes. These ratios can't be communicated to electricity traders because they depend on the decisions the traders ultimately make, ie, they must be computed in real time. A counterargument was raised that, even though precise real time information might be impossible to provide, one should consider the consequences (costs) of relying upon an approximation to these real-time values in deciding on the merits of a bulletin board system for this information. How high are these costs, and are they very high all that often?

One significant flaw in the British system is its attempt to have a commercially simple system that was inconsistent with the engineering and physical reality. Commercial simplicity was argued for on transparency grounds; it was straightforward enough so that commercial dealings were commonly arranged one day in advance. People soon figured out that by "gaming," they could take advantage of the simple commercial rules, and of the discrepancy between them and the physical reality. This is a major reason why the "uplift" (a cost adder to cover overheads and mistakes) has grown so dramatically in the U.K. system.

A striking feature of the hypothetical calculations which underlie the pool market model is the difference between the marginal costs of electricity calculated by the model and people's notions of how much it might cost. This would indicate that there is considerable opportunity for efficiency improvements under marginal cost pricing. The downside of such a change is that life is more complicated, because marginal cost prices keep changing.

One participant argued that the inefficiency in a centralized system compared to the bilateral system arises from having centralized dispatchers making decisions on which plants to run during that half-hour. The potential for improved efficiency through new bilateral transactions is not a story about plant construction, the pool mechanism, or demand-side profiles; bilateral deals are already commonplace in these areas. The only decision still under the purview of the central dispatcher in each half-hour on the system is that one plant should run and another shouldn't. The speaker argued that the chances that bilateral

players would do a lot better at this activity than the central dispatcher were fairly low.

It was pointed out that double contingency pool dispatch rules are not an inherent restriction of any market model; such constraints can be relaxed to single contingency or some other standard altogether if desired. Further, it is possible to define what services apart from dispatch (such as six-second AGC and five-minute security constrained dispatch) the pool had actually been providing, in the event that one would dispose of the pool concept entirely. Once defined, those services can be provided in the external market. It is important to realize that it's not the pool that provides such services, it's the pool that controls the elements that provide the services.

An important issue which was raised was: What should be done next in terms of experimentation on the system? A better quantitative understanding of how serious the congestion problem really is would be very helpful. A big first step would be to perform the 8760 calculation. It's not trivial, but it's also not impossible to do. If the result is that the system is typically not congested most places, most of the time, then the bilateral model is very appealing. If, however, the system is congested or expected to be congested much of the time, the next question is how one would deal with it. The pool market model is a system which is designed to deal with congestion. It assumes that there's going to be a significant amount of congestion. If there is not a lot of congestion, then it's not a problem.

Papers and outlines handed out at the 11/30/93 seminar:

These papers and outlines, as well as copies of the agenda and a list of participants, were mailed out to all HEPG members. If you would like to receive a copy of any of these papers, please call Connie Bums (617/495-1318). Please do not cite or circulate any of the 'Draft' papers without the author's permission.

- Abbott, Cathy *Bilateral Negotiation Model of the Electric Utility Industry* Draft, November 29, 1993.
- Henderson, J. Stephen *Market Structure and Transmission Puzzles* Draft outline, November, 30, 1993.
- Kean, Steven, *Problems in Pools (As Illustrated by the UK Model)* Draft, December, 1993.
- Simmons, **W. M.**, *Gas Industry Evolution*, Draft, December 1993.