HARVARD UNIVERSITY

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HARVARD ELECTRICITY POLICY GROUP
PLENARY SESSION

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MEETING SUMMARY

The movement towards a more competitive market in electricity raises a number of issues regarding the design of access policies and market as well regulatory institutions. The Harvard Electricity Policy Group (HEPG) is pursuing the analysis of many of these questions. A series of working seminars have focussed on the state of policy development and identification of key issues that need to be addressed as part of the transition. This plenary meeting reviewed the results of these interim sessions on jurisdictional challenges, stranded assets, and market operations to discuss the next steps in the research agenda.

Thursday, January 13th

The first day of the session began with presentations summarizing the special seminars on "State-Federal Jurisdictional Issues" held in Cambridge on 12/16, and "Stranded Assets. Towards Analyzing the Options" held in Cambridge on 1/7. A presentation on the implications of a competitive electricity market for integrated resource planning (IRP) finished out the day.

Jurisdictional Challenges

In passing the Energy Policy Act of 1992, Congress created new authorities and confirmed, at least in part, the policy direction of moving towards a more competitive electricity market. The EPAct does not address, much less resolve, all the associated issues that arise in the regulatory structure that governs the industry. In particular, there are gaps, overlaps and moveable boundaries between federal and state responsibilities for regulation and rate setting.

Market Results.

Paper: Stalon, Charles *Redefining Regulatory Jurisdictions for the Electricity Industry* Draft paper, 1/13/94

Speaker:

The most important energy issue facing the nation today is the restructuring of the regulatory community and the electric industry it regulates. Failure to provide leadership on these issues threatens the efficiency of the industry. With the Energy Policy Act of 1992 (EPAct), Congress clearly intended to lay the groundwork for the evolution of a competitive electricity generating industry. Although the language of the EPAct gives the impression that Congress had in mind the restructuring of investor-owned utilities, in practice all publicly-owned and consumer-owned utilities will also be affected.

The Congress, in making possible these changes in the electricity industry, did not provide any guidance on restructuring the industry's regulatory system, despite the fact that it is inconceivable that we would be able to restructure the industry without making changes to the regulatory processes and jurisdictions that govern the industry. It is important to persuade regulators to engage actively in this effort to rethink their jurisdictions -- these are all unpleasant ideas, but if we can make them *familiar* unpleasant ideas, we can make progress.

Because generation and distribution companies in this new sector will have to interact across interconnected transmission networks, some new system of coordination of transmission activities will be necessary. We expect to see firms in three different companies trading across a transmission network. Whether this should be handled by modification or coordination of existing regulatory bodies, by new regional institutions, or by some combination of the two, is not clear.

Since competitive pressure comes from forces outside of the regulatory system, what is there to gain from engaging in a debate about jurisdictional changes? This is not going to be a process where we will be able to clarify all the alternatives and make choices among them. It is also not going to be the case that the state commissions will agree to call on the Federal Energy Regulatory Commission (FERC) to take regulatory authority away from them.

The most essential parts of the system to try to address coherently are the natural monopolies of the transmission network and control of dispatch. The quasi-judicial process regulators use to reach decisions makes it very difficult for them to make coherent policy. Needed jurisdictional changes must be guided into existence by the only two agencies capable of taking a national and international view -- the FERC and the DOE -- although they will have to work with other organizations and regulators.

There is an inherent tension in our present system of fragmented regulation. When states complained in '89, '90, '91 about the FERC granting transmission rights and threatening protection of native load, the FERC responded that "Everybody is somebody's native load." -- this is a national economy and an integrated grid. The states responded with, "No, that's not an acceptable standard.", and in so doing they have imposed a standard that every move must be a Pareto move - the FERC must only make steps which benefit all parties. This is a difficult or impossible task, and the FERC is looking for both guidance and suggestions.

Objectives for restructuring regulatory jurisdictions:

Outcomes to be avoided:

- *Competition in transmission services should be avoided* There is no way to realize more efficiency by offering competing transmission facilities. The public nature of transmission facilities mandates that transmission facility siting and use be made as efficient as possible. Because these facilities must interconnect, this is a national problem.
- *Competition in control systems should be avoided*
- *Institutionalization of a system of bilateral trading should be avoided.* The objective of restructuring should be to promote efficient dispatch.
- *Institutionalization of an inefficient system of pricing transmission services should be avoided.* *Uneconomic physical bypass of distribution facilities should be avoided*

Outcomes to be sought:

- Regulators must continue to regulate transmission and control services. Some regional or national regulatory arrangement is necessary to regulate transmission and control. Regulators must try to put in place a system of efficient transmission pricing. Pricing of transmission services should encourage the optimal location of plants, optimal sizing of transmission facilities, and optimal trading of power.
- Regulators and industry leaders should affirm and protect the voluntary system of cooperation on which the reliability of the system depends, at least until some other system is developed.

Strategies for restructuring jurisdiction:

- The FERC could impose non-discriminatory pricing standards on transmission-owning utilities for unbundled and currently bundled services. Such an order would require states to unbundle transmission services, and once it's unbundled, the FERC can assert jurisdiction. This would lay the groundwork for integration-by-contract rather than by-firm, and would highlight the need for defining and pricing transmission services and assets.
- The DOE and REA could encourage open access on all federally-owned transmission facilities.
- Further, federally-owned transmission assets might be sold to incorporated transmission companies to facilitate the development of a transmission sector. This might be used as a means of easing the stranded investment problems of utilities.

The magnitude and complexity of the transformations initiated by the EPAct exceed those of any other industry which has undergone regulatory restructuring in the past. Electricity industry regulators must simultaneously deal with the restructuring of the industry and the reallocation and redefinition of jurisdictions among themselves. It may be necessary to create new regulatory entities to resolve these problems. An important step is to get all regulators intensely involved in the debate over their roles. Realistically, the federal government is the natural source of leadership on these issues.

Discussant:

When you talk about transmission access, you're talking about a public good - everyone who wants access should be able to get it. When you talk about transmission services, you're talking about a private good. When you merge these two, you're going to have conflicts that the regulatory system must deal with. I disagree that FERC has the authority to preempt state regulatory authority and unilaterally take over jurisdiction over transmission. It will take some changes in legislation.'

Transmission services are like an automobile. You want several things in a car - speed, economy, and luxury. It's very difficult to get all three of those things in the same automobile. In transmission you have reliability, you have efficiency, and you have equity. The speaker has placed reliability as the highest priority, and I agree with that. But he seems to place efficiency above equity, in terms of how costs should be spread around between all participants. But one of the reasons why regulation was instituted in the first place was for the sake of equity, not for the sake of efficiency.

Fragmentation of regulation should be viewed as a check and balance, not as an impediment. With respect to the local fairness issue, I would submit that the compensation simply wasn't right, and it is the natural duty of states to look out for these interests.

Re-valuation of transmission facilities should be discussed. Some recovery of stranded investment could be handled through unbundling transmission services and charging the FERC with the responsibility for overseeing the re-valuation of transmission assets. Generation assets are another matter, since they are retail-based - **I** don't think that could be done without some addition federal authority.

Transmission: Jurisdictional Confusion.

Traditional state regulation of transmission assumed that transmission assets would be used almost exclusively for state jurisdictional customers. Open access upsets that tradition and creates a need for expanded cooperation between state and federal regulators as well as new approaches for developing transmission expansion and transmission pricing.

Speaker:

In planning, siting, pricing and providing access to transmission services, no matter where jurisdiction falls between the FERC and the state commissions, neither one has enough authority to make the system work and develop coherent policy on its own. Therefore the debate over transmission services has to encompass both federal and state jurisdictional authority. But the debate over transmission, with few exceptions, has been carried out at the federal level, and has not existed at the state level, because these services are bundled in retail rates. Becausd there is considerable federal authority over access and pricing, these issues have been the center of the debate. But even if we got the pricing perfect, there is currently no way to develop a rational transmission scheme, because planning and siting authority remain with the state commissions.

How do we price transmission? The FERC views transmission as one of the unbundled services that a utility may provide. State commissions, thinking about retail customers, price transmission like anything else - the facility was planned for the native load customers, and so transmission will simply be treated as any other utility asset in the retail rate base. Although they don't think about it in these terms, state commissions thereby implicitly impose on retail ratepayers the residual revenue responsibility for guaranteeing a revenue requirement to a utility for that transmission investment.

When state regulators think about regulatory policy, it is inextricably tied up with their notions of interclass equities at the retail end. Certain customers have had obligations placed on them - in return for the obligation to serve and priority of access from the utility, the retail monopoly customer has been made the guarantor of revenue requirements to the utility, no matter how efficient or inefficient the utility is in the use of its assets.

The black hole of the 1992 Energy Policy Act is that, if the FERC orders access where it can't be provided with existing facilities, the utility incurs a good faith obligation to get state siting authority for a new line. State siting boards have historically made two decisions when they site and certify a new line. One is, yes, there's a need for the facility and here's where it can go, and the other is, we will put the line in retail rate base and make the retail ratepayer the guarantor of the residual revenue requirements for the investment, regardless of how the FERC prices wholesale use of the line. There is a possibility of decoupling these two decisions.

States tread carefully around the question of unbundling transmission, because, as our last speaker pointed out, this raises the possibility of FERC preemption of state control of transmission ratemaking. Another option would be the exercise of some joint FERC-state ratemaking authority. Some mechanism for joint decisionmaking could solve a lot of problems, such as mergers, pooling arrangements, and jurisdiction over registered holding companies. Regional transmission groups (RTGs) are not going to be able to address all these issues alone, because state commissions will still have the obligation to do the decisionmaking for their states. RTGs are not going to do away with this obligation.

Discussant:

I agree with the speaker that the FERC can do a brilliant job with transmission pricing, but if it is not done in coordination with state regulators, there will be underrecovery of costs. The FERC can order transmission access, but if state agencies refuse to site new facilities, we have not realized those benefits. There is a fair amount of sensitivity at the FERC to resolving these issues.

There was a proposal during the legislative debates over the Energy Policy Act, to create a process whereby, if it looked like a request fora wheeling order would require siting a new line, the FERC would immediately stay its proceedings and give the effected state regulators six months to report back on any relevant siting concerns before the order was taken up again. This proposal is looking better and better, and the FERC might have the authority to do it, even without new legislation.

The other issue the speaker raised, about some parties asking the FERC to set retail transmission rates, is not an authority the FERC is sanguine about exercising, even if it legally could. Among other things, this opens up the possibility of utilities demanding that the FERC also deal with the issue of assets stranded by these decisions, especially in cases where the state legislature or regulators do not deal with the issue - the FERC is dealing right now with this issue with a case of a retail customer that became a wholesale customer through legislation.

The FERC has been showing more sensitivity to state concerns recently - it has no interest in preempting state authority.

General Discussion

A participant brought up an equity question about retail customers who become wholesale customers and avoid paying the tab for assets stranded by their change in status - why should the remaining ratepayers compensate the utility for these assets? A utility official added to this point that the fact that this problem appeared to fall between the cracks of federal regulatory policy and state regulatory policy was very troublesome to utilities, as well. Perhaps it will take a wave of retail bypass, like the MBTA and Mass Electric, or a lot of municipalizations, before some one will "own" the problem. Another participant said that it was because the decisions involved were very difficult to make - no state regulator, for instance, is happy about passing on billions of dollars of stranded costs to the ratepayers who benefit least from the transition to a competitive market.

Another participant noted that the Energy Policy Act makes a distinction between wholesale and retail, whereas the Federal Power Act draws the line between interstate and intrastate, with the effect in transmission of using exactly the same facilities for exactly the same transaction, but characterizing it in entirely different ways. This system of states exercising authority over one set of rates and transactions while the FERC exercises authority over another over identical facilities is not stable.

A state regulator said that the FERC hinting that it might assume this or that authority had a chilling effect on state commissions that might be thinking about devoting some of their own limited resources to solving some of these problems.

Another participant recommended looking at the FCC model for joint conferences, where federal and state regulatory authorities discuss policy in a structured way and make non-binding recommendations to their respective bodies. "It creates a vehicle for dialogue."

Stranded Assets

The transition to a more efficient electricity market maybe dominated by the path more than the destination. In many parts of the country, excess generation capacity combined with large sunk costs leaves some utilities with potentially stranded assets well in excess of the respective firm's book value of equity. In earlier discussions, the HEPG emphasized the large magnitude of the sunk cost exposure as the principal obstacle to an orderly transition to a more competitive market. Progress in implementing the movement to an efficient new market structure depends on defining a workable strategy for allocating the sunk costs of stranded assets. Given the potential scale of the problem, differences between companies and across jurisdictions will dictate different approaches. In order to guide decisions, it is necessary to develop a better understanding of the options and their consequences.

An earlier HEPG special seminar on stranded assets discussed the analytical issues that should be addressed in designing a transition strategy. The many questions are too complicated and too important to yield to a single or simple prescription at this stage, but much progress can be made in refining and elaborating the questions. The focus is on a summary of what is known and what needs to be done in order to develop the basis for a more informed public debate that will serve the customers, the industry and its regulators.

Legal Transitions, Compensation and the Cost of Shifting Costs.

Customers have an interest in an efficient transition to a more efficient industry. Along the way, customers will face many conflicting pressures for supporting different cost recovery strategies and the accompanying extent and phasing of the movement to a more competitive market for electricity. The costs of a transition to a more competitive market will not be independent of their allocation. Principles for compensation can be derived from a normative ex ante perspective that considers incentives and risk allocation.

Speaker:

Someone said this morning that someone's $100 billion in transition costs was someone else's $100 billion in savings, and that's why no one is indifferent to this issue of costs allocation. But there is another question, which is: What are the real costs of this transition? To what extent do the ways we decide to allocate costs affect these real costs? The whole point of going to a competitive market is to expand the pie, not just carve it up into different slices.

Stranded assets in electricity are not all the same. With a power plant, the difference between the historical cost and the market-clearing price is the potential exposure in a competitive power market. With NUG contracts, it's high cost purchase contracts. There are "regulatory assets", like special accounting practices that defer cost recovery. Ina competitive market, the value of these assets is zero. At our October plenary session, we had a presentation that showed that the potential exposure for some firms was from 65% to 125% of the book equity of those firms, under various assumptions about how that exposure takes place. There have been other analyses along these lines - the fact that this exposure is going to be very different for different firms is a further complication.

The emphasis today is not on refining our estimate of these costs, but on developing strategies for dealing with stranded asset allocation. There is one set of people outside the industry that say, 'The shareholders took their risk, they've already been compensated for taking that risk - let the chips fall where they may."

One presentation at a seminar earlier in January examined the costs to society of compensating losers when the government changes the rules. The conclusion was that, under the assumption that the government usually make policy changes for good reasons, then compensation isn't a good idea. This conclusion is based in part on a symmetry argument - the same government that doesn't tax gains when its policies create value somewhere, shouldn't have to compensate when it takes away value. The idea is to avoid the imbalance of ex ante incentives that are created, for instance, when people who live in a flood plain get free government insurance.

Under regulation, however, some of the assumptions implicit in this theory are violated. The symmetry assumption for returns to shareholders, for instance, does not hold. Under regulation, if assets are valuable or costs are low, the benefit is passed through to the ratepayer. Therefore if assets are not valuable, the argument could be made that the ratepayer should have to absorb the cost. Another assumption that is violated is the implicit freedom of choice in investment. Utilities don't make investment decisions on the basis of the expected risk and return on those investments -sometimes they make investments on the basis of compulsion - the six cent law in New York is a good example. So there are theoretical reasons to think that, under regulation, it is the ratepayer who receives the benefits of investment (apart from the normal rate of return given to the shareholder) and should therefore bear the costs. This is one framework for thinking about allocation of stranded costs.

Another framework for thinking about the allocation of these costs is what could be called "The Cost of Shifting Costs", which starts from the assumption that the way you cut up the pie ultimately will also affect the size of the pie. We have just started trying to understand the real costs associated specifically with a regulatory transition in electricity would be, how big they would be, and how they would affect the ultimate size of the pie. If utilities want to recover stranded assets, they had better be able to demonstrate that, if they don't, bad things are going to happen to the industry and the country.

Real costs associated with the transition to a more competitive electricity market include:

- Transaction costs of the transition (this seminar, for instance, where people try to figure out what is happening). These are assumed to be small.
- Price distortions from sunk costs being allocated to consumers cause a widening gap between electricity rates to those consumers and the marginal cost of producing electricity. However, with low elasticities of demand in the short-run, these price distortions will be relatively small.
- Bankruptcy or near bankruptcy conditions at a firm, which have affect the management of the company. Quality of service and investment decisions are affected, etc. Some work has been done on the costs of financial distress. After it files for Chapter 11 protection, for example, what kinds of decisions does a firm make - does it emerge from bankruptcy weaker or stronger than its competitors? The common argument for quick reorganization is that post-bankruptcy costs tend to be small.
- 'Transition Cooperation": Potentially, the single largest real cost associated with how sunk costs are allocated is the degree of cooperation among different players in settling this allocation. If allocation is not settled, strategic behavior by individual players will determine both transition process and destination. The experience in railroads suggests that these costs could be very large -- managers are "mesmerized" by the stranded asset problem and disputes, paralysis, or opportunistic behavior can constrain the realization of the benefits of a competitive market.

Discussant:

Looked at from a historical point of view, it won't always be entirely clear to anyone what brought individual investment decisions about -- whether the regulator made me do it or whether I made the regulator make me do it -- for these investments, an equity perspective won't serve very well. In some cases, there was some allocation of costs between shareholders and ratepayers at the time the investment was made, and perhaps these agreements can be revisited usefully.

Strategies for Cost Recovery.

Companies will differ in their mix of explicit contracts or implicit obligations, mandatory or discretionary investments, and settled versus prospective rate decisions. The many alternatives for recovery of sunk costs have different time profiles, different incentive effects, and different distributional results. In some cases, the scale of the problem may require using all the options. In others, the details matter in selecting an appropriate strategy for recovery.

Speaker:

The options for dealing with stranded assets fall into four basic categories:

- Open markets quickly and let the chips fall where they may. This strategy would allow electricity costs to be reduced as soon as possible, and would minimize transition costs for ratepayers, but be catastrophic for some utilities and social programs that depended on them.
- Cut utility costs and use the savings to offset stranded costs in various ways. This option allows recovery of some stranded assets, although not all if they are very large. It minimizes rate increases for customers but by the same token delays rate decreases.
- Redistribute stranded costs, e.g. write-up of transmission assets to offset the write-down of other assets. Redistributing costs to ratepayers is politically unpopular. Writing up transmission assets delays rate decreases to customers. Utilities with large stranded assets and nowhere to redistribute them to would not be helped.
- Postpone competition as long as possible. This strategy won't work against things like self-generation or municipalization, and delays the potential benefits of competition. Price caps might offer a form of regulation that is more consistent with competition.

Contract, rather than tariff approaches to pricing might offer utilities more flexibility to be responsive to individual customers.

[A brief discussion of an announcement by Public Service New Mexico was discussed at this point. An agreement was reached for restructuring PSNM's rates while handling its excess assets. The stipulation agreed to was a $30 million overall rate reduction, allocated non-proportionally, with the larger benefit going to the major industrial loads and other customers with choices. Rate reductions were in the range of 2% to 11 or 14% for different customer classes. Book equity of PSNM is about $700 million - total writedowns came to $180 pre-tax, $109 after-tax, over a period of years. About two thirds of this came from write-downs of higher-priced generation and regulatory assets, and a third came from a cost-reduction pass-through, the result of some down-sizing and efficiency gains in the company. In exchange, the company came to some agreements about future pricing flexibility for specific customers, and that nuclear assets currently on the books would be deemed used and useful.]

Discussant:

I will try to cast for you the position that small consumers and their advocates take towards these issues. First, consumers believe in competition, and they don't particularly trust regulators. They believe that competition will lower their rates. They believe that current rates are at best fair and are probably too high. One of the difficult things to do will be to say simultaneously that the industry is becoming more competitive and that they will also have a higher electricity bill. This paradox will also make it very difficult to shift additional transition costs to them. The argument that society in general is going to be better off, while the bills of small customers are going up, is not going to be well received.

Consumers have a high private discount rate. If competition means higher costs to them, customers would prefer to postpone competition -- this may present an opportunity for arbitrage between private and societal discount rates. Customers have a preference for not raising rates now as opposed to the promise of a future discount. A price cap system might have the advantage of keeping rates for small customers within politically acceptable limits, while introducing some aspects of competition into the industry.

Utilities will have to brace for significant write-downs, no matter what is done in terms of transition relief. Utilities with high rates are also the ones with the biggest stranded asset problem, and so there will be limits to what they can do in terms of redistributing these costs to their ratepayers. Consumers don't see this as their problem - it's seen as a utility shareholder problem.

Stranded asset allocation, as we saw with PSNM, is going to have to be negotiated on a company-specific basis, because each firm's circumstances are so different. This issue is going to be slugged out in state commissions utility by utility, and you don't need retail wheeling to enable an industrial customer to wring out significant concessions on rates.

<u>Report on Research in Progress:</u> A Competitive Electricity Market - Implications for Integrated Resource Planning

(Rather than summarize this talk, we have included below an edited transcript of the entire presentation.)

How does the prospect of competition affect decisionmaking and related regulation during that time period, and how does the prospect of competition affect integrated resource planning, which is where we make a lot of those decisions currently concerning investment? IRP is the basis for supply side and demand side commitments, the principal basis for making those decisions. Minimizing the present value of revenue requirements is the principle decision criterion, and it's a long term horizon, 20 plus years.

The prospect of competition has some decided implications for integrated resource planning and they're going to be difficult to deal with. The first is that absent changes, IRP is going to be perceived by many stakeholders, most particularly the utilities, as increasing shareholder exposure to competition and therefore will become an increasingly contentious and difficult effort as a result. It's important to understand why this is so, so we can see whether there's anything we can do about it. That leads to my second conclusion, that there are some adjustments, both to IRP and some related regulatory policies that can eliminate or at least ameliorate these particular problems. It is possible that use of IRP is going to be perceived as increasing shareholder risk. What can be done about this?

Where is the shareholder exposure come from that people are worried about? It comes from the difference between the average cost of generation, including return on capital, and the wholesale market price. That difference, when generation costs exceed the wholesale market price, translates to asset values which are below the book values of the company, and that difference is the potential shareholder exposure. This average generation cost is both owned and purchased, not just on the balance sheet, but also purchased. Differences in either can affect the outcome. The tenor of much of the discussion today seems to focus on average generation costs being the source of the problem. Of the $200 billion that we're up to, more of the problem comes from oversupplying the wholesale market. Because of the excess capacity overhang, we have depressed the wholesale market price far below replacement cost or long-run equilibrium price. That's what's giving rise to the big stranded investment, not the fact that we have expensive resources here.

So leveraging either place is important -- reducing costs or raising the market price – and indeed that's the critical question for IRP. If IRP either increases average cost above the levels that a competitive market would, or if it depresses the market price below the level that a competitive market would, IRP will be perceived as increasing risk. Both dangers are real, and IRP can do both and as currently practiced, in fact, does do both, in two specific ways. The first is that the investment rules that are implicit in IRP, which generally don't give any particular consideration to the value of deferring commitments and use the current level of utility discount rates, typically about 10 percent, both of those together result in higher levels of investment or commitment to power contracts, and therefore lower market prices than would be expected in a competitive market. Simply stated, we employ too much capital in the generation side of the business with the rules that we currently use. Second, the IRP process, due largely to the imposition of some social costs, can raise what, from a customer perspective are generation costs, higher than they would be in a competitive market.

So we have a set of investment decision rules which drive the market price down, a set of social programs whose cost recovery makes it appear that generation costs have gone up, and the consequences are unhappy. There is one more that we have to keep in the back of our mind, which is the prospect of an asymmetrical risk reward profile, i.e. the lower of cost or market opportunity fora customer, can also dampen the enthusiasm of utilities for certain types of investment and we're going to have to be mindful of that as well. That's a harder problem to solve.

I'm going to turn first to the decision rule problem and try and do justice to that, because that's my personal biggest concern with IRP. Most utilities and regulators currently use present value revenue requirement analysis (PVRR) within the context of IRP to evaluate major investments. Most of you know how this works. You get a couple of different cases with different resource plans. You prepare a bottom up, cost-plus estimate of the revenue requirements, compare them, and choose the one that has the lower cost. Implicitly when you compare any two plans one's got more capital than the other and hopefully lower operating costs as a result, and the PVRR calculation is designed to figure out when employing more capital produces production cost savings that make it worthwhile. The capital-operating tradeoff which is implicit in PVRR.

Unregulated firms face these same kind of decisions every day. They don't use PVRR. They typically use net present value analysis. In the electricity context you could start with the market price of energy and capacity. Subtract off your fuel and O&M to get an operating cash flow. You subtract off your income taxes and the construction outlays, your capital expenditures, and you get an after tax cash flow to equity. You put a discount rate and present value that kind of thing, and if that turns out to be positive, you make the investment, and if it doesn't, you don't. Why is this difference important? Under similar assumptions about market price, the two techniques are actually quite similar -- one's pre-tax and one's after-tax. But an investment with a positive net present value, i.e. one that a private investor would undertake, would also generally reduce PVRR if it's looked at in that context. So a rule to choose investments which minimize PVRR is roughly equivalent to using the NPV rule that a private investor would use.

Unfortunately finance theory complicates the matter a little bit. Basically, positive NPV is the right decision rule only for non-deferrable investments. That's what the theory says: If you can either do the option now, or you lose it forever, positive NPV is the right way to decide. Thus by implication, minimizing PVRR decision rule, is also appropriate only for non-deferrable investments. Unfortunately, most significant utility generation investment opportunities are deferrable, and without recognizing the value implicit in deferability, the PVRR rule can result in uneconomic investment.

The problem that we have with excess supply right now and low market prices is not principally a problem of difficulty in forecasting demand. It's a problem of not recognizing the uncertainty of demand and embedding this uncertainty in the decision rules. If you introduce the possibility that you can spend some money and defer the decision a little while, you might learn something important and your decision might change, so the option to defer is valuable.

Options have their most value when you're dealing in volatile markets. They're not very valuable if the markets are fairly certain. In New York in 1988 there was a forecast of long run avoided costs, which was a forecast of market prices. And there was an actual price in 1989, which exceeded the forecast. Commitments were made in the 1988 to 1991 time-frame, based on the forecast, and they all made economic sense relative to this forecast. The difference between the forecast and actual prices begs the question: What was the value of deferability in 1988 or 1989 in New York State to see what happened to oil and gas prices, and to see what happened to the natural gas business and all the rest, and to see what happened to wholesale market prices? The answer is: The value of flexibility in New York State was a saving of about ten billion dollars relative to what actually occurred.

We can have very volatile markets relative to your forecast. Investment decision rules can reflect that. What's the practical import of all this? For non-deferrable investments, an unregulated firm says invest if the net present value is greater than zero, or in other words if the present value of the cash inflows divided by the PV of the investment is greater than one -- that's one an unregulated firm would do for non-deferrable investments. In a PVRR context, invest if the change in present value is less than zero, i.e. you save, PVRR, goes down; or if the present value of the operating savings divided by the present value of the capital revenue requirement is greater than one. That's what the theory tells us is the right decision rule in the unregulated and the regulated context for non-deferrable investments.

When you go over to deferrable investments, the hurdle goes up. The present value of the cash inflows divided by the investment has got to be somewhere from 1.3 to 2.0, as opposed to 1.0, before that investment makes sense, because the option to defer is so valuable. What does that imply for the regulated, for the PVRR context? It implies that the present value of the operating savings divided by the present value of the capital revenue requirement, as we would calculate it in PVRR, might correspondingly have to meet that higher hurdle, 1.3 to 2.0. There are very few investments that we make in the utility business that would meet that higher standard.

We've been making investments and fixed commitments in this business pretending that the cash flows were not volatile when they are. And every now and again we get unlucky, and we have over-investment in the business. The key efficiency problem that we have is not that the power plants are operated inefficiently or whatever. It's that the big ticket commitments that are being made are being made in a regulated political context according to a set of rules which are different than the rules that would be used in a competitive market, and that can make an enormous economic difference.

So much for the decision, for the option value. The other thing that I mentioned was discount rates. In a competitive market, the volatility that I referred to will pass right to the bottom line, to utility earnings. The market price goes down, utility earnings go down; if it goes up, they go up. Whereas right now utility earnings are largely insulated from fluctuations in the wholesale market price. When you move from one to the other, that volatility, to the extent it's correlated with the stock market and with economic activity generally, increases the risk of the underlying stock.

The higher discount rate can be a big difference, relative to the ten percent discount rate of which we are also fond in this industry. So continuing to use too low a discount rate can basically make uneconomic investments -- uneconomic to an unregulated investor -- look attractive in the regulated context, and perpetuate excess investment at lower market prices. Too much capital deployed in the generation business. The relevant question here is not what the risk is today, but what the risk will be when the investment is being recovered in the future.

The other part of the puzzle for IRP was not that it would drive the market price lower, but that it could drive utility generation costs higher. Basically there area couple of reasons that generation costs are higher than they would be in a competitive market. The first is that environmental externality programs, however administered, can result in the selection of resources with higher cash costs than would otherwise be undertaken, or they can accelerate the need for resources which will move forward dollars. Likewise, DSM transfer payments are often treated as generation costs for rate-making purposes. The continued imposition of such social costs in the competitive market is viewed as increasing shareholder exposure, and utilities are going to want less.

Even if we solve both of those problems -- if we used unregulated market investment criteria and we dealt with the social costs, good investment decision rules and the proper discount rates are no guarantee of good outcomes. Life is still going to be uncertain. That problem doesn't go away, it just happens less often than it does today. If the regulatory rules permit customers to enjoy the lower of cost or market -- i.e. stick with the portfolio when it's in the money, and abandon the portfolio when it's under water -- the distribution of economic benefit of an investment is going to be asymmetric, and we're back in the transition cost problem.

All of these problems can be dealt with. There are three things to do to bring regulated investment more in line with unregulated investment, and therefore ameliorate those concerns. First is incorporate option value into the PVRR analysis -- it's conceptually easy to do, and it's mechanically not even that hard. Bringing that point of view to how we think about deploying capital within PVRR would be a very important improvement.

Utilizing a higher discount rate is also not something that's hard to do if we have the will, and it will go a long way toward alleviating concerns. We've fallen into the view that an IRP isn't a good IRP unless it includes a portfolio of long-term commitments against another portfolio of longterm commitments, and somehow if you just only worry about the next three, four, or five years and put off a decision until then, that's not a valid portfolio. Well, of course that's not the way an unregulated firm would view that problem. They like short-term commitments in keeping flexibility, so that we would need to do something about how we construct the options to fully include that. At the bottom line, there is no unregulated business which makes investments which are forecast to pay off in fifteen to twenty years at a ten percent discount rate. Most PVRR-based investments are forecast to break even somewhere between year 15 and 24, at a ten percent discount rate. And changing the rules so that we don't deploy capital that way is an improvement.

What do we do about the social programs? Utility concerns can be alleviated by shifting the cost recovery to a non-bypassable portion of the tariff. If somebody goes to wholesale or retail wheeling status, what they pay as T&D costs includes this number. Finally, what to do about the symmetry question? In short, I don't know. This is inextricably bound, in some sense, with the transition cost recovery problem. When we're making new investments in this uncertain transition period, where we don't know where we're going and who, and how we're going to get paid back, the first question we want to ask is: Who do we want to be the residual risk-taker for these kind of investments? Historically it's been the retail rate payer. Is it the rate payer, is it the shareholder, or it some sharing of that residual risk if the investment turns out well, or if the investment turns out poorly? If it's a commission-approved set of investments, the rate payer gets the benefits, the rate payer pays the costs. The only problem is we need an enforcement mechanism to assure that they can't avoid their responsibility for commitments that turn out to be economic, either by self-generation or by retail-wheeling or by wholesale-wheeling. If it's the shareholder, how can you make the shareholder responsible for gains or losses, particularly losses associated with investments which are not made at their discretion? How do we classify the investments into those which are discretionary and not? Finally, if rate payers and shareholders are going to share the residual risk-taking, then in fact we have to resolve both these issues, and we have to come up with some rules. Thank you.

Friday, January 14

The second and final day of the session featured a panel discussion of transition costs strategies, with a variety of viewpoints represented on the paned The panel was followed by a presentation summarizing the special seminar on "Natural Gas Market Operations" held in Cambridge on 11/30, and finished up with an overview of future research plans and interests.

Panel Discussion on Transition Cost Strategies

The review of jurisdictional issues, stranded asset problems and options for the transition combine to present a number of challenges for the industry. This panel discussion focused on the integration of these issues from the perspective of the electric utilities, their customers, and the regulators. [The below is a summary of notable quotes from panelists and other participants.]

'The stranded asset issue will be bounded by the amount of writeoffs that would take them from BBB+ to BBB- -- after that, some kind of relief will have to be offered, or we'll face a lot of bankruptcies."

"'The reason why utilities will lose money is from industrials leaving the system. But inertia is a tremendously powerful force. Industrials fundamentally don't want to be in the power business, so I think time is an ally."

"You don't want a utility to fall below investment grade, because in some markets that utility will not be able to finance. And you can't have a capital-intensive company with an obligation to serve the public that can't finance."

"'The existence of captive customers has given utilities little incentive to plan or respond to market signals. Utilities deal mainly with regulators, not customers."

"We used to only worry about return on equity - more important today is return on investment. Utilities have to make investment decisions on a much shorter time frame - we can't exposed our shareholders to a greater degree than they already are."

"We have crafted a set of performance-based rates, which shifts our focus from a total concentration on asset-based management and regulation to value-based asset management, and value-based regulation of the enterprise."

"Strategies that add to or merely perpetuate a rate structure for utilities will not work because they are broadly perceived to have become an identifiable part to be blamed for the loss of the state's competitive attractiveness, industrial migration, and loss of jobs."

Market Operations

At previous meetings of the HEPG, we have observed that the natural gas industry is much farther down the same path, and many of the issues raised about the electricity market have a familiar ring. There is a great deal to learn from studying the natural gas experience. But there is debate about the relevance of that experience in the organization of electricity market operations.

There is general agreement that there is great room for improvement in communication between the two industries, to benefit from the experience and improve the design of policy for market operations in both. The special seminar on November 30 developed these issues and identified the key questions that should be investigated to guide the choice of structure for developing electricity market operations.

Pool Market Model.

Outline: Hogan, William *An Efficient Electricity Pool Market Model* Draft, January 1994

Speaker:

What we are trying to do with this discussion is to understand better the implications of two broad alternative approaches to operating an efficient wholesale market. The stylized characteristics of the two extremes are the bilateral market, where bilateral trades occur at arms length in the short run and open access to the grid is provided by transmission owners at posted prices. Network congestion problems are handled through allocated capacity rights and trading in the secondary market. You'll hear more about the specific operation of this market from the next presenter. The pool market model features the operation of short term markets through a centralized dispatch. System stability and network congestion are handled as part of the pool dispatch. Capacity rights are implemented in the short term through transmission pricing, and long run investments are handled in bilateral markets. This approach assumes that this centralized system is necessary to preserve the stability of a complicated, non-linear system. The question is, what do you give up to do it this way? The fact that marginal costs vary quite a bit in a single system means that there is a big incentive for people to exploit these differences to make short-term trades. To the extent they can't capture this value, they leave a lot of money on the table.

Transmission consists of two things - the actual wires, and moving electrons around on them. From this perspective, transmission and dispatch are the same thing. The only way you control the flow of electrons is how you dispatch the plants. And dispatch within a pool is very complex.

So if we want to assign capacity rights to the transmission grid where people can efficiently trade these rights in the secondary market, and then the loads change, we have to figure out a way to set up a bilateral trading system where people can discover these load ratios in order to get the value out of reallocating capacity rights in the system. With central pool dispatch this is handled automatically.

The contract network model provides an internally consistent system for creating long-term rights of use of the transmission grid. The short-term market operates, in effect, to guarantee efficient trading of these long-term rights and the "clean up" any discrepancies between rights and actual use of the system.

Discussion:

In the opinion of one participant, the commercial transaction of trading capacity rights in no way has to replicate the timing of the dispatching transaction. We don't have to transact pork belly by pork belly in the pork belly market - if you look at the differentials over a month or whatever period, the transactions are much easier to accommodate.

The price mechanism should be set in the market outside of dispatch operations. Dispatchers should handle capacity allocation and actual movement of the electrons.

Gas Market and Bilateral Trading.

Speaker:

We're not going to have time to construct a perfect market structure - if electricity follows the timeline of natural gas, this is all going to happen very quickly, and we should spend our time trying to facilitate the transactions that are happening right now. We need to focus on what industry structure will foster the most commercial innovation, and find ways of promoting economic efficiency that way. I am interested in finding ways to accelerate the change, and of finding ways to participate in a more efficient market, because there is a huge economic benefit to be gained by us and by the economy.

There were two things that started opening up the natural gas industry - one was competition on alternative fuels and the other was gas on gas competition. Death spiral was what we called it -large customers left the system, and people said, 'That's ok, we'll just put the remaining costs on the franchise load". So you raise your prices, shed more load, raise prices, shed more load, etc. This competition set off a chain of regulatory changes - the most important one was FERC Order 436, that provided open access. Within a year and a half of open access, more than 50% of the market was out of traditional jurisdictional sales. The transaction volume now is unbelievable.

We have everything we need today to make these transactions in the wholesale market. There area number of critical rules that need to be in place -- some constraints that need to be reduced immediately to allow the market to grow. We need a process for scheduling and nominating electricity, as we have in natural gas, We need dispatch information - the pools realize that they have valuable information - they do not let outsiders get hold of it. We need a marketing affiliate rule, so that I can compete with equal access to information. The FERC and the state commissions need to move to a level playing field in transmission pricing. We need to reduce the reporting requirements to the FERC, which act to squelch competition.

Discussant:

We're going to have two transitions in electricity, not one, because the gas industry was less vertically integrated than electricity is. The transition is going to be slower and more uneven geographically. Bilateral trades will be the first try, and we'll eventually move to a bilateral system with an underlying pool basis because of increasing congestion problems.

There's a good chance that some private participants in this transition will want to skip the socially beneficial step of creating pools, so someone - state regulators, the FERC - will have to step in at some point and figure out how to create the right incentives for people to minimize the amount of inefficient investment these individual firms make.

Research Agenda

Summary and Discussion of Research Topics in Progress

This session featured short presentations of current research in progress by various members of the group.

Contract Issues in Electricity	Dan Fessler, CaPUC
Norwegian Electric Supply Industry: A Case Study	Jim Boothe, CaPUC
Environmental Implications of Greater Competition in the Electric Utility Industry	Henry Lee, HEPG
Over judicialization of Regulatory Decisionmaking	Ashley Brown, HEPG
Benefits of Competition	Bill Hogan, HEPG

Summaries of these topics by their authors have been included in the mailing with this summary.

Handouts for 1/13/94 Harvard Electricity Policy Group plenary session in San Diego

Most of these papers, presentation overheads, and outlines were produced for the San Diego session and are in draft form only. Please do not cite or quote any materials marked "Draft" below.

- Abbott, Catherine and Jeffrey Skilling (Untitled draft presentation on Competitive Market Model), January 1994
- Anderson, Steven *Recent FERC Orders Concerning Stranded Investment in the Electric Utility Industry* January 7, 1994
- Brown, Ashley *The Overjudicialization of Regulatory Decisionmaking,* Natural Resources and Environment, Vol 5 No 2 (Fall 1990)
- Brown, Ashley *Some Thoughts On State-Federal Jurisdictional Issues in Transmission, and the Transition to a Competitive Electricity Market* Draft paper, January 12, 1994
- Stalon, Charles *Redefining Regulatory Jurisdictions for the Electricity Industry* Draft paper and presentation, January 13, 1994
- Flaim, Theresa *Methods of Handling Transition Costs for the Electric Utility Industry,* Draft presentation, December 9, 1993
- Hogan, William *An Efficient Electricity Pool Market Model* Draft presentation, January 13, 1994
- Hogan, William *Stranded Assets and Options for the Transition: Legal Transitions, Compensation, and the Cost of Shifting Costs* Draft presentation, January 13, 1994
- Schnitzer, Michael *A Competitive Electricity Market: Implications for Integrated Resource Planning* Draft presentation, January 13, 1994