A Competitive Electricity Market: Implications for Integrated Resource Planning

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The prospect of a competitive market for electricity is being taken seriously by the HEPG with focus to date on the magnitude of potentially stranded investment and the structure and rules of a competitive environment. Today's purpose is to focus on the transition period itself, specifically:

- How does the prospect of competition affect investment decision making and related regulation?
- In short, how does the prospect of competition affect Integrated Resource Planning (IRP)?

IRP means many things to many people, but for the purposes of today's discussion, the key characteristics of IRP include:

- Basis for supply-side and demand-side commitments
- Minimizing the present value of revenue requirements (PVRR) as the principal decision criteria
- A long term horizon (20+ years).

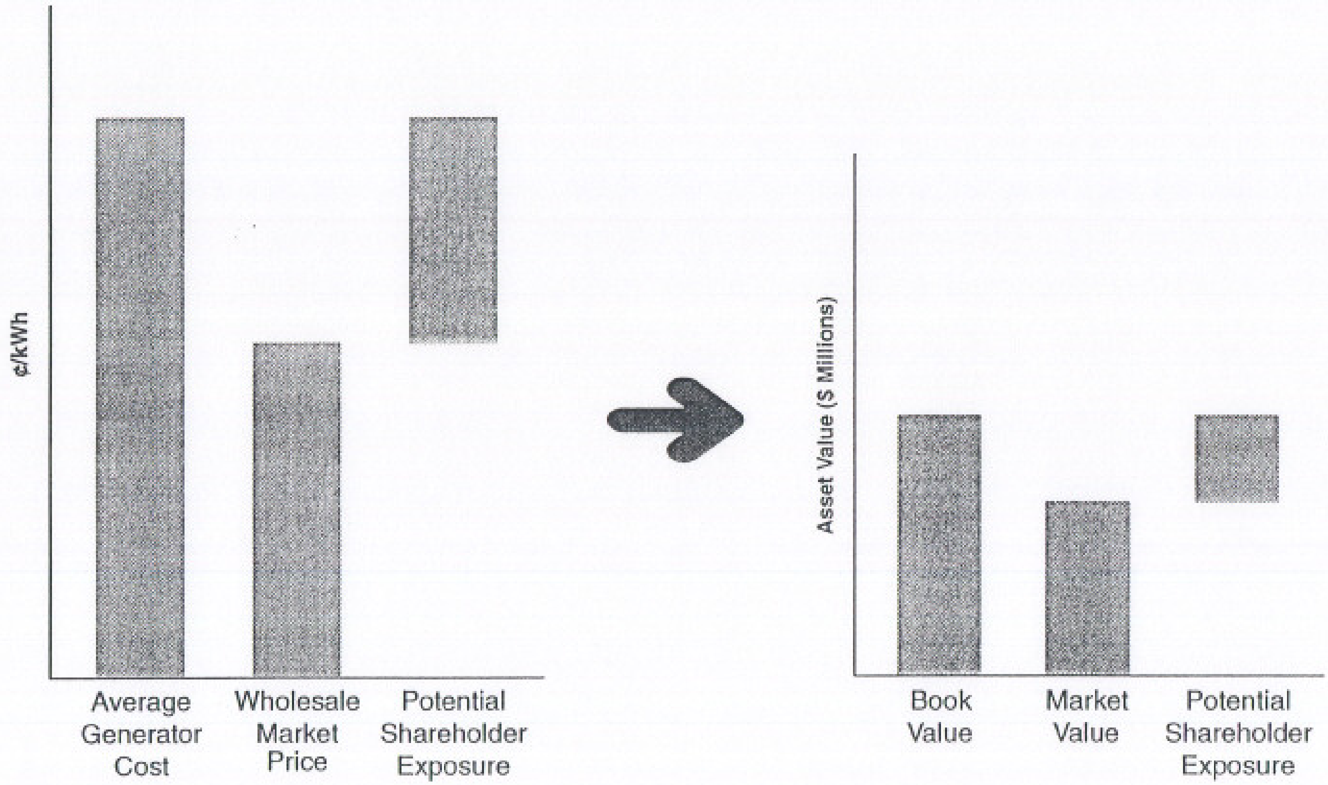
The prospect of competition has decided implications for Integrated Resource Planning:

- Absent changes, IRP will be perceived as increasing shareholder exposure, and therefore will become an increasingly contentious and difficult issue as a result

- Adjustments to IRP and related regulatory policies can eliminate/ameliorate these problems.

The remainder of this session is devoted to exploring each of these conclusions in turn.

By way of review, the magnitude of potential stranded investment is determined by the gap, if any, between the average cost of generation, including return on investment, and the wholesale market price:



The exposure represented by potentially stranded assets can be aggravated by the current IRP process:

- The investment rules implicit in IRP -- particularly the lack of any distinction for deferrable investments and the current level of utility discount rates -- result in higher levels of investment and lower market prices than would be expected in a competitive market

- The IRP process -- due largely to the imposition of various social costs -- can raise generation costs higher than they would be in a competitive market.

These two problems are the principal issues to be resolved. In addition, the prospect of an asymmetrical risk/reward profile can dampen the enthusiasm of utilities for certain types of investment.

INVESTMENT RULES

PVRR and NPV Equivalent

Most utilities and regulators currently use Present Value Revenue Requirements (PVRR) analysis within the context of the IRP process to evaluate major investments, while unregulated investors typically use net present value (NPV) analysis:

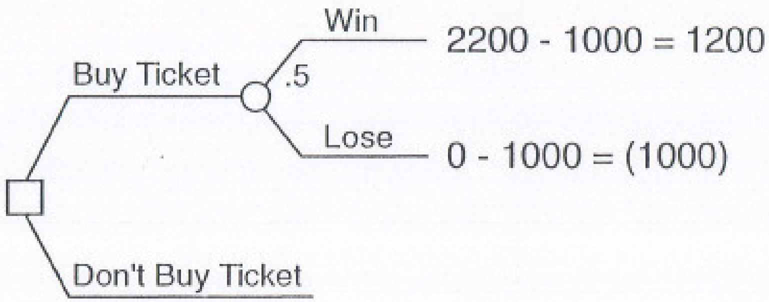
	Market Price of Energy and Capacity
—	Fuel and O&M Expense
=	Operating Cash Flow
—	Income Taxes
—	Construction Expenditures
=	After Tax Cash Flow

Under similar assumptions, the two techniques are similar -- that is, an investment with a positive NPV will also reduce PVRR -- and a rule to choose investments which minimize PVRR is roughly equivalent to a positive NPV decision rule.

Unfortunately, the rule to choose investments which minimize PVRR is often the wrong decision rule and can easily easily result in uneconomic investment:

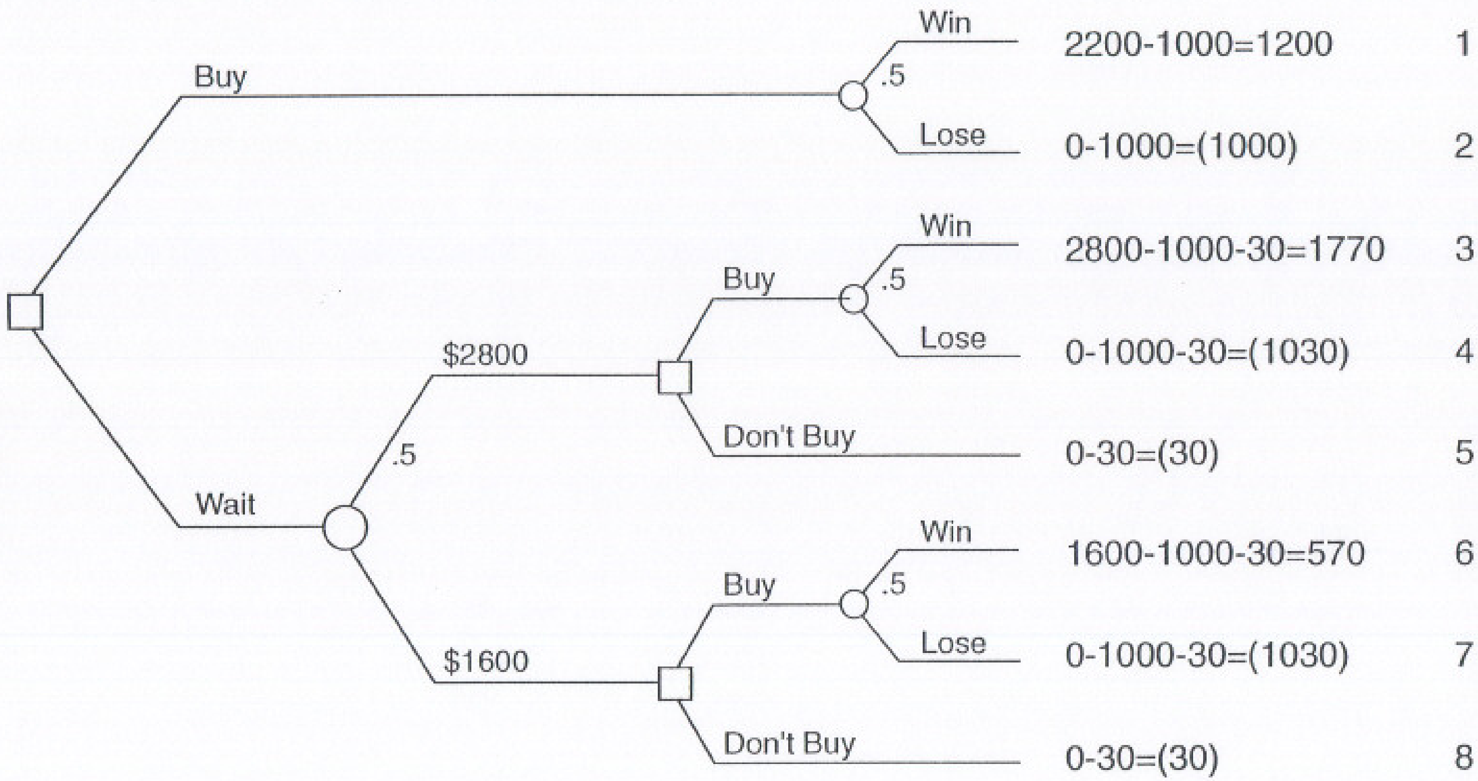
- Positive NPV is the right decision rule only for non-deferrable investments
- Thus, the PVRR decision rule is appropriate only for non-deferrable investments
- Yet, most significant utility generation investment opportunities are deferrable -- and without recognizing the value implicit in deferrability, the PVRR rule can result in uneconomic investment.

To illustrate why deferrability is valuable, consider a single example involving a $1000 lottery ticket:



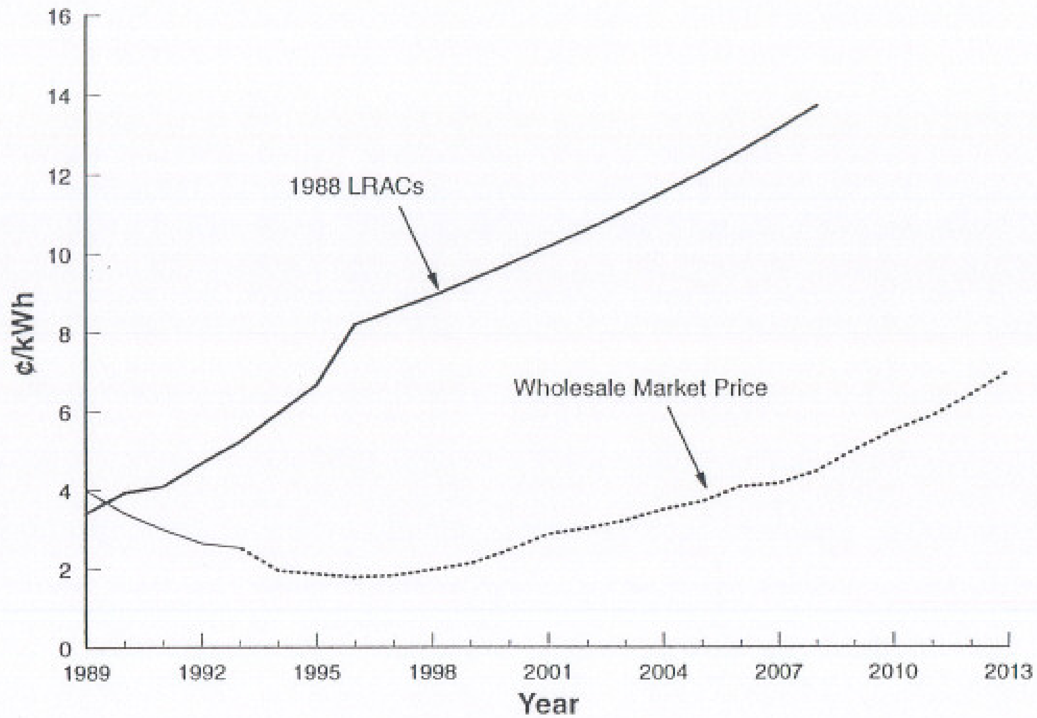
The expected profit of $100 is an attractive opportunity -- and relative to the investment, by the way, about the savings associated with many utility investments.

But suppose that the payoff is not $2200 -- but either $2800 or $1600 -- and for $30 we could wait to find out before buying the ticket:



Buying the ticket now is the wrong answer -- the $30 to defer the decision is money well spent because expected profits go up by 70 percent, and thus the ability to defer an investment can be valuable, particularly if volatility is likely to be present.

To bring the lottery example closer to home, consider an actual utility's LRAC forecast in 1988 versus actual and projected wholesale market prices:



If you had made a long-term commitment based on the 1988 projection, how much would it have been worth to defer the commitment for a few years?

INVESTMENT RULES — Tougher Hurdle

The effect of this deferral option value is to raise the threshold for economic investment:

Non-Deferrable Investments			Deferrable Investments		
Unreg		PVRR	Unreg		PVRR
NPV >0	➡	ΔPVRR <0	---		---
$\frac{\text{PVCF}}{\text{PV Inv}} > 1$	➡	$\frac{\text{PV Op Savings}}{\text{PV Capital Rev Req}} > 1$	$\frac{\text{PVCF}}{\text{PV Inv}} > 1.3 \text{ to } 2.0$	➡	$\frac{\text{PV Op Savings}}{\text{PV Capital Rev Req}} > 1.3 \text{ to } 2.0$

With competitive markets brought on by retail wheeling, utility earnings will no longer be sheltered from price fluctuations in markets for wholesale energy and capacity -- and the risk inherent in those fluctuations will increase required equity returns and the cost of capital:

Industry	Unlevered Beta	Difference in Unlevered ROE
Electric Utility	0.35	--
Steel	0.70	2.50%
Aluminum	0.88	3.75%
Auto	0.93	4.10%

Continuing to use too low a discount rate -- the current utility cost of capital, for instance -- will continue to make uneconomic investments look attractive and perpetuate excess investment and lower market prices.

In some cases, IRP can also raise generation costs higher than they would be in a competitive market:

- Environmental externality programs can result in the selection of resources with higher cash costs, or can accelerate need
- DSM transfer payments -- lost revenues and program costs -- are often treated as generation costs for ratemaking purposes.

The continued imposition of such social costs in a competitive market is viewed as an increase to shareholder exposure.

Even if these issues -- lower market prices and higher generation costs -- are dealt with successfully, this is one other issue which could dim utilities' enthusiasm for certain investments:

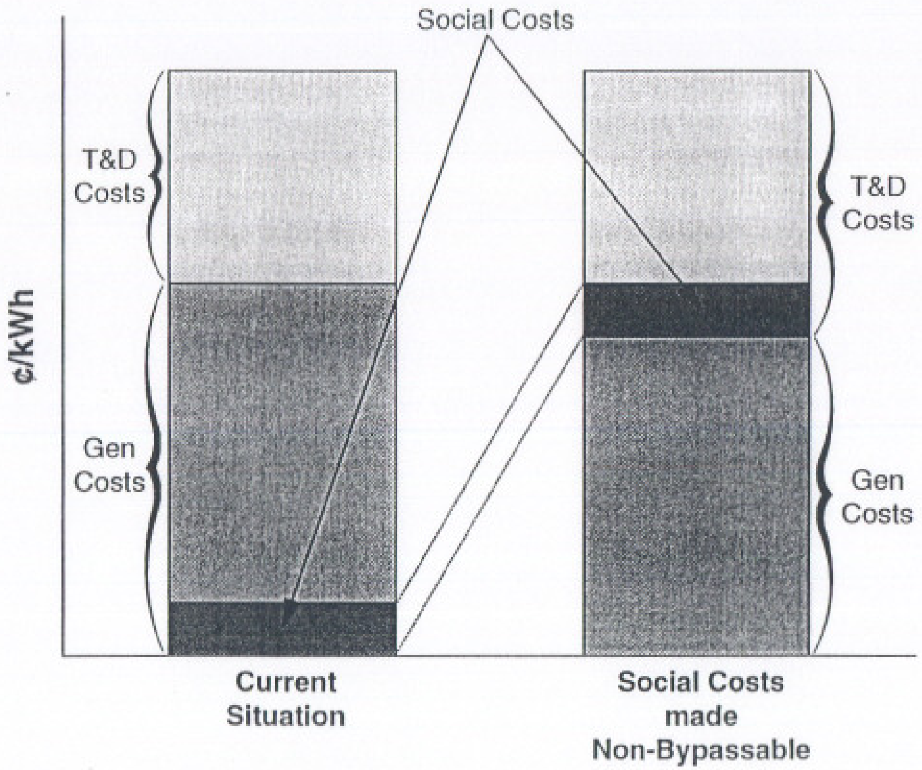
- Good investment decision rules and the proper discount rates do not guarantee good outcomes -- some investments will be uneconomic
- If the regulatory rules permit customers to enjoy the lower of cost or market, the distribution of economic benefit will be asymmetric.

All of these problems -- the two inherent in the current IRP process and the symmetry question -- can be meaningfully addressed. Three actions will significantly reduce the problem posed by current IRP decision rules:

- Incorporate option value into the PVRR analysis
- Utilize a higher discount rate, particularly for long-lived investments
- Make sure that alternatives that do not required long term fixed commitments are given adequate consideration.

DSM and externality programs have been actively debated in many jurisdictions:

- We do not want to add to that debate today
- Utility concerns can be alleviated by shifting cost recovery to a non-bypassable portion of the tariff:



The asymmetric benefit allocation is perhaps the most difficult of all the issues as competition increases -- and in many ways is similar to the transition cost recovery problem -- but a logical approach exists to remedy this situation:

- First, the residual risk-taker must be designated:
  - Ratepayer
  - Shareholder
  - Combination
- Then, if it is the ratepayer, an enforcement mechanism must be developed to assure that they do not avoid their responsibility for commitments that turn out to be uneconomic
- Or if it is the shareholder, the question of involuntary investment must be resolved
- If ratepayers and shareholders will share in residual risk-taking, then the questions associated with each must be resolved.

Edited transcript of a presentation: "A Competitive Electricity Market: Implications for Integrated Resource Planning" given at the Harvard Electricity Policy Group plenary session in San Diego, January 13, 1994.

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 for a 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.

This is 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 are a 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 long-term 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.