Performance Based Regulation
A Discussion Paper

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Performance Based Regulation (PBR) is not a new concept. It has been used in the last several years in various guises including incentive ratemaking, non-traditional fuel adjustment clauses and special accounting and incentives for DSM. What *is* new is an accelerating tendency toward competition in the industry and, in some states, a decision that the time is ripe to revisit the regulatory mechanisms that have evolved over the past decade and decide whether they continue to meet the needs of the industry.

Where Regulation Is Today

The traditional role of regulation has been to prevent investor-owned utilities from abusing their monopoly position by over-charging customers. This is done through rate cases where a periodic and fairly detailed review of the utility's costs takes place. In most states, the review happens only at the utility's instigation, and the outcome is usually a decision to raise rates.

More recently, traditional regulation has taken on a second task as well. Driven by various generation investment debacles (chiefly nuclear), an increased sensitivity to the environmental damages of electricity generation and consumption, and the realization that electric generation is no longer a natural monopoly (if it ever had been), many PUCs have been mandated to review utility resource acquisition plans. These IRP processes have provided an opportunity for public/social input in a number of areas including cost minimization, cost/environment tradeoffs, benefits of a diverse resource mix, conflicting goals of rate versus bill minimization and the desirability of resources with high up-front costs but low operating costs, i.e. renewables.

Today, this two-pronged approach to regulation has been called into question by five events:

1. The market for electricity has become more competitive. This happened in part because it has become clear that wholesale generation is not a natural monopoly and in part because some customers, particularly large customers, have self-generation options.

2. Electricity rates are relatively high, in large part due to nuclear costs over-runs and oil and natural gas backout strategies.

3. Costs for competing fuels, chiefly oil and natural gas, are at historic lows, creating a stranded investment problem.

4. The recent recession and the changing global economy have made large customers more price-sensitive while, at the same time, strengthening their threat to move operations elsewhere.

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[1] In developing this paper, I benefited from the comments of my colleagues at RAP – Cheryl Harrington, Ed Holt, David Moskovitz and Carl Weinberg. Of course, any errors or inconsistencies that remain are not their responsibility. In fact, because PBRs are an emerging topic on which my own thinking remains fluid, I, too, refuse responsibility for any errors. Ellen Baum edited several drafts of this paper, and her handiwork is clearly evident. I suspect any errors are her doing.

5. Deregulation is seen as successful in other U.S. industries and in the electricity industry in other countries.

The confluence of these events has placed the industry in a state of flux, and today it is reasonably clear that the rules of the game will change. What is less clear is what the nature and degree of change will be. In considering appropriate regulatory structures, there are three non-exclusive choices: retaining the existing regulatory mechanisms; abandoning existing mechanisms and relying on markets to decide what gets built and who pays; or modifying existing regulatory structures so that regulated monopolies will maximize profits by implementing public policy well. The last, modifying existing regulatory structures, is a choice to use PBRs.

Creating PBRs

The definition of PBR is no clearer than it is for the other major acronyms of utility policy, say LCP or IRP. This paper defines PBRs to include any mechanism which attempts to link rewards (generally profits) to desired performance e.g. having a diverse resource mix, operating at low cost, etc. In many of the examples offered later in this paper, PBRs apply to electric utilities, but in some cases, particularly where there is retail competition, PBRs would apply to non-utilities as well.

If the definition of "PBR" is fuzzy, then the goals of a PBR can hardly be completely clear. For this paper, the goals (which are held by various players in varying degrees) include:

1. Provide utilities with better incentives to reduce their costs and with a substantial portion of the savings accruing to customers.
2. Streamline regulation to be less costly and, more importantly, less subject to time consuming debate and slow decision-making.
3. Insure a rational IRP planning and acquisition process.
4. Enhance, or at least maintain, the current roles of DSM and renewables.
5. Enhance, or at least maintain, the current sensitivity toward the environment.
6. Build on the existing utility/regulatory structure (avoiding the syndrome which begins step 1, tear apart everything that currently exists).

Policy makers must consider as their first step what goals they wish PBRs to address.

The second step is to develop a PBR structure. The structure of a PBR defines the incentives that a PBR produces. A PBR structured to focus only on limited areas may be counter-productive. For example, structuring a PBR to focus solely on minimizing costs may bias a utility against good least cost planning. This could occur by producing a bias against resources with high up front costs but low life-cycle costs. A cost-only PBR could cause a utility to ignore important non-cost criteria, such as maintaining a reliable, diverse resource mix or reducing environmental impacts. Structuring a PBR right means understanding, from the start, all the performance goals the PBR is intended to address.

Finally, a PBR structure is only as good as the numbers that support it. If the numbers are not right, there is a good chance that customer bills will be unrealistically high or utilities' financial health will be threatened. The right PBR structure might be $X per customer plus inflation minus productivity. Getting the numbers right means starting with the right "X" and using the right inflation index and productivity factor.

PBRs will not be one-size-fits-all. A PBR for a wires-only utility will look different from one for a wholesale generating company. Separate PBRs for each aspect of a utility's business S generation, retail distribution and transmission S may be desirable.

While there is no shortage of unanswered questions on the future of utilities, two possibilities are particularly important when thinking about PBRs. Divesture, if it occurs, makes development of a PBR much simpler. It eliminates the need to police self-dealing between the generation and distribution wings of the company and leaves the distribution utility indifferent to the impact of increased sales on the generation wing. Retail competition, on the other hand, makes developing a PBR more complicated, for two reasons. The utility will generally have less flexibility on the rates it can charge, and a PBR needs to be designed for the new, non-utility suppliers.

Types of PBRs

PBRs can be divided into three broad categories. The first group, bill and rate caps, are attempts to replace or supplement rate cases. A second group, targeted PBRs, rewards or penalizes utilities for specific aspects of behavior, such as good performance in acquiring cost-effective DSM. The final group, portfolio PBRs, focuses on what resources are acquired. Some portfolio PBRs offer ratemaking alternatives in the current environment of integrated regulated electric utilities. Others represent efforts to define the rules under which electricity markets of the future will function. Generally, these latter approaches apply equally to utility and non-utility suppliers of electric generation.

The remainder of this paper surveys these three types of PBRs. In addition, there is a brief discussion of fuel adjustment clauses. Fuel clauses often produce perverse incentives and are an example of a newly created genre, the anti-PBR.

Rate Caps and Bill Caps

Rate Cap/Bill Cap schemes are designed to replace traditional utility rate regulation and give utilities better incentives to control their costs by relying on increased regulatory lag as a mechanism to encourage cost cutting. Under traditional regulation, if the utility's cost of some input S say labor S rises, profits are reduced until the utility's next rate case. At that time, rates will reflect the new higher costs, thereby restoring profits to the level they would have been without the higher expense. The argument goes that the only reason the utility would make any effort to control costs is to avoid a short-term loss of profit until the next rate case can be processed. The solution S to stretch out the period between rate cases S is predicated on the theory that longer time periods between rate cases place more profits at risk and thus strengthen the incentive to avoid cost increases or pursue cost savings. In recent years, commissions have considered both rate and bill caps to set revenues and lower short-term costs.

Stretching out the regulatory lag period is not a new idea. It has been discussed in academic circles for at least twenty years and is a feature of regulation is some states, for example California and New York.

Bill caps and rate caps, however, can have very different results. Rate caps present utilities with very powerful incentives to promote electric use and equally strong disincentives to DSM. This pro-sales, anti-DSM bias is similar to the biases of traditional regulation, without decoupling or a lost revenue adjustment, but the effect is even stronger precisely because the regulatory lag period is extended. Because rate caps are clearly inconsistent with minimizing costs, they should be avoided except in very limited situations, such as wholesale electricity sales where investments in DSM are not an issue. (This is not a problem in the telephone industry where rate caps have been in use for some time because there is nothing in telecommunications that resembles cost-effective, energy efficiency.)

Bill caps, on the other hand, produce the same cost cutting incentives as rate caps but very different and much better incentives for energy efficiency. Bill cap PBRs are a logical choice for retail sales (sales to final users electricity).

A simple bill cap PBR consists of four basic elements:.

1. Following a rate case which looks at the usual cost items and customers served, an allowed base revenue per customer (RPC) is set at a reasonable level. This RPC, with certain adjustments, remains in place for a number of years, thus stretching out the regulatory lag period.

2. Once a year, the RPC is adjusted based on a pre-specified index. One simple approach allows a growth based on some broad inflation measure, less adjustment for productivity improvements. One concrete example would be to let revenues per customer rise by the annual change in the CPI less, say, two percent for productivity improvements. Another alternative might be to base the increase on the increases of other electric utilities' average bill to their customers.

3. Often, the utility is allowed to directly pass through certain costs, which are typically referred to as "exclusions" or "Z-factors". These costs are generally desirable expenditures and/or outside the utility's control. Examples might include the costs of DSM, R&D and Superfund site cleanups.

4. Periodically, perhaps once a year, their would be a true up. If the utility had actually collected more revenue than allowed amount, there would be a rebate to customers. Conversely, if the utility under-collected allowed revenues, then a surcharge would make up the difference.

By following these steps, the net effect is that the utility will have a specified amount of money to serve customers= needs. If they spend less, their profits rise. But profits hinge on cost control, not customer usage. This reduces the disincentive for DSM and the incentive for load building.

Opponents of both rate caps and bill caps are likely to argue that the improvement in incentives is still too weak and, in any event the resulting rates/bills will be too high. This is a fairly easy argument to make. Generally, the PBR debates will occur first where utility costs are already high. High costs may be a result of high fixed costs that are likely to go down relatively fast through amortization of canceled plants, front-end cost recovery of recently added expensive plants, etc. Where costs are high, it is probably easier to control cost escalation. In such a situation, locking in current costs plus an average level of inflation will be too generous to utilities and too costly for consumers. The answer is to avoid caps which include high starting points and high growth rates.

Another potential objection is that utilities will be given additional discretion to discount rates to encourage or retain sales under a rate or bill cap. Under a rate cap, a utility would want to drop rates to price sensitive (industrial) customers while raising them for less sensitive (residential and small commercial) customer groups. Under a bill cap, the utility could also do this or could, at its option, simply drop some rates and let the revenue reconciliation recoup the revenue loss. Many would argue that fair cost allocation among customer classes is an important policy decision that Commissions should make explicitly and not leave to be determined by default. There are two responses here. First the utility's ability to raise rates can be restricted in various ways. For example, Niagara Mohawk has proposed to cap the increase applied to any individual rate element and to be prohibited from shifting rates across customer groups. Another approach, that applies only to bill caps, would not allow any revenues lost due to discounting to be recovered through the rebate/surcharge mechanism.

There are other PBR approaches to overall revenue levels. One possibility would be to put the entire utility up for sale through bidding. The winning bidder would pay the current owners of the utility a fixed price, essentially the accounting value of their investment. The winning bid would be the one that could serve customers most cheaply. Conceptually, this idea is appealing, but the list of practical hurdles is breathtaking.

Targeted Incentive Schemes

Targeted incentive schemes have been around for quite a while. In the case of DSM incentive programs, a utility which acquires DSM at or below avoided costs is allowed to keep a fraction of the savings. In designing a workable PBR mechanism, some limited use of targeted incentives may be beneficial.

The biggest problem with targeted incentives is that, by definition, they focus on a single aspect of utility performance. A targeted incentive needs to be large enough to capture management's attention, so it is impractical to have a number of schemes for one utility.

On the other hand, one or two targeted incentives can play a role if they are artfully directed. A non-exhaustive list of candidates includes:

to come up with arguments that clauses provide reasonable incentives.

the fuel clause. Fuel clauses tell utilities that fuel savings are valueless.

perspective, ratepayers are providing a no cost insurance policy against fuel price risks, and there is no reason to place any value on the fuel risk benefit which these technologies provide.

1. Incentives that reward DSM and/or renewables acquisition.

2. Bill index schemes where a utility=s profit depends on how its bills change viz. an index of comparable utilities.

3. Emission index schemes, similar to bill indexes but with the reward/penalty based on emission of one or more pollutants.

Portfolio PBRs to Encourage Resource Diversity

PBRs which focus on minimizing utility revenues are fairly straightforward. The goal is simply defined and quantified, and there is no controversy over its legitimacy. Furthermore, revenue PBRs, by definition, are applied to a franchised monopoly where there is not adequate competition to hold prices in line.

For a portfolio PBR, the goal S to get a ?good@ resource mix S is ultimately subjective and multi-dimensional. In addition, the very notion of portfolio PBRs is new. There is no track record of past successes and failures to rely on.

To complicate things further, it can no longer be assumed that a utility will be a monopoly forever. Many PBR schemes take the form of "do a good job and we will let you charge higher prices." But the legal authority to charge higher prices is an empty promise if the firm faces competitive pressures that will not allow the price increase.

The remainder of this paper outlines 11 approaches to portfolio PBRs. The first group, items one through four, are styled to apply to monopoly utilities. The rest are applicable to monopoly and competitive environments alike. The list is intended to stretch one=s imagination as to possible schemes. On further reflection, some may not rightly be called PBRs, and others may be without merit. The latter group is listed in rough order of their ease of implementation.

1. Incentive based on social cost of resource mix.

Periodically, the social cost, including external costs, of the utility's resource mix would be determined and compared to the social cost of a 'business as usual' resource mix. The utility would receive a bonus/penalty based on the results of the comparison.

Pros

$ Addresses all resources in a single framework.
$ Aims squarely at the true value of DSM and renewables, at least to the extent that those values are reflected in the externality adders.

Cons
$ Heavily bureaucratic/litigious. The "business as usual" mix is a regulatory fiction which can be argued indefinitely. The externality adders are almost as difficult to determine.
$ Not transferable to states which do not quantify all, or at least most, externalities.
$ Misses the risk reduction effects. The risk reduction argument presumes a willingness to pay a little more, on average, for a mix that is less risky. But by paying a little more, the incentive goes down.
$ Tricky to set up. If it is too generous, customers will be paying a bonus to the utility for acquiring a resource mix that they would have otherwise not acquired. This may not be politically acceptable if the incentives get large. On the other hand, if the scheme is set so that penalties are likely, the utility will simply opt for the "business as usual@ mix, which is precisely the wrong result.

Want Least Cost

possible futures. One concern, heightened by competitive pressures, is that utilities will not maintain their interest in maintaining a diverse fuel mix. Most utilities today focus on natural gas fired generation for any new construction. A strong argument can be made that a more balanced portfolio, one including some resources that are not subject to the same risks as gas fired generation, would be a far better option.

2. Incentive based on revenue volatility.

Each year, regulators would look at the change in the utility's average bill and compare it to the changes experienced by similar utilities. If the utility experienced a smaller change in bills than the others, it would get a bonus. Conversely, if its bills were more volatile, it would be penalized.

Pros

* A direct attempt to get at the volatility of bills.
* Once the comparable utilities are picked and the formula is in place, the mechanism is purely mechanical.

Cons

* There is no objective method to value stable rates, so selection of reward/penalty levels is fundamentally arbitrary.
* Focuses on changes in year to year costs, not one time shifts in the economics, i.e. fossil fuels cost more for many years or new environmental regulations make a generator much less economic. On the other hand, protection against these one-time shifts is probably more important.
* There is a good chance that the primary effect of this approach would be to change the way utilities contract for fuel by creating a preference for long-term contracts or futures market activity. It is not obvious that renewables and DSM would be helped and conceivable that they would be hurt.

3. Incentive based on diversity of resources.

In this approach a bonus/penalty incentive mechanism is based on the mix of resources the utility acquires. For example, a matrix could be created saying any fuel type constituting less than five percent of the utility mix would be recovered at 120 percent of its costs. If a resource were over 50 percent of the mix, the utility would get only 95 percent of costs. The bonus/penalty could be tied to something other than costs if that were desirable.

Pros

$ Explicitly addresses resource diversity.
$ Once set up, the mechanics are simple.

Cons

$ Incentive values are arbitrary.
$ Can give odd messages, e.g. if you are heavily nuclear and oil, build coal.
$ Probably would require different reward/penalty matrices for different utilities. This could create a front page test problem.

4. Recover utility fixed expenses through the retail wheeling rates or other non-avoidable charges.

The debate over how retail wheeling rates should be set has become reasonably well focused, though not resolved. In order to avoid uneconomic retail wheeling and simple cost shifting among customers, the rate should be set at the utilities regular retail rate less the avoided costs the utility would see were it not providing the customer with generation.[2]

The retail wheeling rate question is critical to developing a rational framework for utility operation. A well-designed retail wheeling rate gives the wires monopoly a chance to recover investments relatively safely.

Pros

$ Provides strong mechanism for cost recovery almost regardless of the future industry structure.
$ Concept is now fairly well understood and has developed reasonably wide support.

Cons

$ Unacceptable to retail wheeling advocates looking for large, near-term rate reductions.

5. Require all suppliers (or customers) to purchase minimum percentages of DSM and renewables.

Suppliers of retail electricity, or conceivably customers in a retail wheeling world, would be required to purchase minimum percentages of DSM and renewables. Specialized DSM and renewables firms, possibly including the distribution utility could be set up to insure an adequate supply. In a non-wheeling world, a utility incentive/penalty scheme could be fashioned along similar lines.

Pros

$ Targeted at getting a specific result. Little concern about unintended and undesired results.
$ Simple to understand and explain.

Cons

[2] Retail wheeling rates are discussed more fully in D. Moskovitz, T. Austin, C. Harrington and C. Weinberg, *Future Utility and Regulatory Structures: If You Don't Know Where You're Going, Any Road Will Get You There*, The Regulatory Assistance Project, December 1993.

$ Strong command and control flavor.
$ Potentially difficult policing effort, particularly if requirement placed on buyers, or if number of sellers, is large.
$ Relatively inflexible. Once requirements are set, they will not be easy to change even if conditions warrant a modification.

6. Surcharge on traditional generation.

All generation from nuclear and fossil sources would be taxed, say at one mill per kWh. (This represents roughly $3 billion nationally). Proceeds would be used to fund DSM and renewable resource acquisition.

Pros
$ Simple, understandable, relatively painless.
$ England is doing it.
$ Easy, if imprecise, method of including external costs of generation in customers' price signal.

Cons

$ May be politically difficult since it has a "tax and spend" flavor.
$ Need to insure money is well spent.

7. Require retail wheeling customers to have adequate and firm capacity commitments.

Historically, the electric utility has tended to be long in generation in most regions, most of the time. As a result, in a retail wheeling world, some customers may be tempted, particularly in the short run, to simply rely on the surplus energy market to supply their needs. When there is a surplus, or if the generation market has a generic tendency to be surplus, this will result in underpricing energy.

Pros

$ Helps insure that adequate capacity will be available.
$ Mirrors current power pool treatment of member utilities.

Cons

$ Difficult to square with interruptible rates.
$ Reduces market pressure to avoid building excess capacity.

8. Power pool pricing policy to reflect capacity costs.

Similar to item 7, above. Power pools would price any purchases by utilities or retail customers to include capacity costs in those hours when loads were high or reliability was threatened. Again, the effect would be to make sure that energy was not under-priced and that customers were not able to get a free ride. The Pros and Cons are as above.

9. Prohibit shifting of future environmental risks.

Owners of new generation would be prohibited from passing the costs of any future environmental upgrades to their customers.

Pros

$ Extends status of most power purchase arrangements to utility-constructed plants as well.
$ Puts fossil fuel on same financial footing as DSM and renewables.

Cons

$ Impact unclear and could be fairly small.
$ Defining costs of environmental upgrades could be tricky.
$ Generation owners will vigorously oppose new laws and attempt to avoid compliance where it is expensive.

10. Give utilities or, customers if there is wheeling, incentives to buy clean and or long-lived resources.

This could be done in any number of ways:

1. Tax credits for expenditures over this year's market price.
2. Loan fund to cover front loading of contract.
3. Use the fossil fuel tax, item 6 above, to buy down the price.
4. A BTU tax.

Pros
$ Market based mechanism
$ Internalizes external costs

Cons
$ May not be effective if the mechanism is seen as temporary, e.g. the preferential tax treatment of renewable development in the 80's.
$ Impact of any given proposal will be difficult to predict.

11. Place a cap on overall carbon dioxide emissions.

Place a national (or regional) cap on CO_2 emissions using a mechanism similar to the current sulfur caps.

Pros

$ Basic mechanism is already well understood/established.
$ CO_2 appears to be a reasonably good proxy for many types of air emissions.
$ Market-based approach

Cons

$ Hard to do on a state/local level.
$ If used as a proxy, misses some important external costs, e.g. nuclear and large hydro.
$ Like sulfur, initial allocations of allowances will be very political.
$ Requires giving up on current voluntary CO_2 policy now.

Conclusion

In theory, it appears possible to use the mechanisms described above (and other similar mechanisms) to develop PBRs that are able to provide utilities with balanced incentives to provide good, low cost service. In doing so, though, it will be important to insure that the approaches adopted offer incentives to utilities to do a good job of providing electricity and not to manipulate regulation in new and nonproductive ways.

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