Integrating Market Processes into Utility Resource Planning

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Market and planning processes are fundamentally different, but mutually dependent. Regulatory oversight of utility resource planning must address a number of issues where these two processes interact. The most fundamental interaction involves resource allocation rules. Integrated planning presents an abundance of alternatives: utility DSM programs, DSM bidding, competitive bidding for private power supplies, utility re-powering, new utility construction. Each alternative relies on different degrees of planning for implementation, and correspondingly greater or lesser reliance on markets. There are, however, no clear principles addressing how much of the need for new resources should be allocated among the various resource options. The allocation question represents the deepest, but least analyzed problem of utility resource planning. A number of alternative models have been adopted, implicitly or explicitly, in various states, including California, Florida, Virginia and New York. These models will be identified, and their advantages and disadvantages characterized. The questions addressed include: (1) Should bidding be used to resolve all allocation questions? (2) Should implementation uncertainties limit reliance on large-scale DSM? (3) Is the franchised utility destined to be a supplier of last resort? What are the costs associated with such a role?

Other regulatory issues also impact the balance between markets and utility planning. Foremost among these are questions involving the bulk power transmission system. For private power development to succeed, there must be adequate transmission capacity and non-discriminatory pricing. These policies can facilitate the bypass of wholesale municipal customers. Large-scale DSM may encourage such bypass by raising rates.

Introduction

Integrated resource planning has resulted in an abundance of alternatives for meeting existing and new demand for electricity services; (1) utility demand-side management (DSM) programs, (2) DSM bidding, (3) competitive bidding for private power supplies, (4) utility re-powering, (5) new utility construction. Each alternative relies on different degrees of planning for implementation, and correspondingly greater or lesser reliance on markets. It is the purpose of this paper to show how the interaction of planning processes and market forces results in resource allocations among the alternatives.

It is the thesis of this paper that the "level playing field" remains a myth of integrated resource planning. Regulatory incentive structures and market forces combine in frequently unanticipated ways to produce results that can be at considerable variance from standard regulatory goals of efficiency and fairness. The problems described here are neither new nor insolvable. They do show, however, a greater intensity than in the past, and point to a new way to look at the integrated resource planning process, namely in terms of its results, not its goals.

The discussion focuses on three phenomena that are driving forces behind the "unanticipated consequences" of contemporary integrated planning efforts. These driving forces are: (1) large customer bypass, (2) large-scale DSM efforts, and (3) large-scale private power projects. In all cases, the driving forces involve "lumpy" rather than small changes to business expectations. The disruptions that lumpy, large-scale alternatives can cause did not disappear with the demise of nuclear power plant construction. We will see how each of these new resource alternatives can turn out to look much like options they were thought to replace.

The bypass phenomenon has been observed more in telecommunications and natural gas than in electricity (Broadman and Kalt 1989; Egan and Weisman 1986), but it is beginning to be a real factor in electricity as well. Elastic customers can decline the retail or wholesale services of franchised electric utilities either through self-generation or by contracting with alternative suppliers. In the latter case, the franchised utility may be called upon to provide transmission services to facilitate such transactions. The political tension associated with retail wheeling limits this alternative largely to publicly owned utilities for whom the wheeling transaction is essentially wholesale rather than retail. Municipalization, however, can make the distinction between wholesale and retail wheeling largely academic.

Large-scale DSM is a rather different phenomenon than "marginal" DSM. In the latter case, DSM is only a small perturbation on the utility's supply plan, and causes no essential change in it. The mobilization of resources necessary to pursue significant fractions of estimated DSM potentials is substantial. Such efforts are difficult to modulate in the face of economic cycles. Nonetheless, explicit or de facto policy in a number of jurisdictions favors this effort as the long-term least-cost resource option, and the dominant resource on which to rely. We will explore the impact of this choice on the competitive position of the regulated utility below.

Finally, the private power industry is maturing from its original PURPA induced status into a significant component of new electricity supply. This maturation has a number of consequences. First, projects are getting to be rather large; 200-300 MW is not uncommon, and there are some as large as 600 MW (Kahn 1991). While this helps to capture economies of scale, it can outstrip power demand for many utilities. Therefore, complex multi-transaction arrangements become necessary, and the need for transmission services grows.

The paper is organized in the following fashion. First, we review critical uncertainties associated with both demand and those resource options that can have the most destabilizing effect on the planning environment. Second, we survey the generic kinds of allocation rules that have emerged from integrated resource planning processes. Third, we examine the consequences of transforming the vertically integrated utility into a "supplier of last resort." Finally, we offer some conclusions about the role of stable expectations in planning.

Uncertainty in Demand and Resource Availability

The role of uncertainty in planning is frequently conceived in a rather passive and stable sense. A particular planning variable is thought to take one or another value, but the realized outcome of the uncertainty does not affect other variables. This conception may not be so relevant to the electricity market today when the range of choices is great and their interactions are complex.

Nowhere is the complexity of planning greater than in the load forecast. Sophisticated end-use methods have proliferated widely in the forecasting profession, but changes in the market may be out-stripping advances in technique. The two main "new" problems of load forecasting involve DSM and bypass. DSM represents a planned alteration in the pattern of consumption, given a particular level of service demand. As the scale and scope of DSM programs grow, increasing effort is being directed toward evaluation of their impacts. These evaluation efforts must eventually come back to the load forecast. Evaluations studies, however, are not a substitute for the problem of forecasting future DSM program impacts. Will there be diminishing returns as programs expand, or will technological innovation expand the DSM potentials? Such questions will become increasingly central to the load forecasting exercise. Bypass is a completely different phenomenon. This represents a change in service demand, not a change in the pattern of consumption. It is not a planned utility action, but rather a customer reaction. Since this phenomenon is new and not widely appreciated, it needs to be discussed in some detail.

Bypass

The bypass motive is transparent. Disgruntled customers leave the franchised utility system because they believe that they can meet their service demands at lower cost through one of two alternatives: self-supply, or transmission interconnection to an alternate supplier. The dominant consideration in bypass decisions is rates. This has been shown through statistical studies of self-supply at the customer level (Rose and McDonald 1991). It can also be illustrated at the aggregate level. Table 1 shows the level of self-generation in three large industrial states, Texas, New York and California. The table also includes data on the size of the industrial sector, and electric rates for all customers and for industrial customers.

The data on which Table 1 is based are somewhat spotty and ambiguous (PUCT 1990; CEC 1990; IPPNY 1991). There is no trade association or government agency whose purpose is to publish reliable estimates of self-generation. Nonetheless, the main lesson of Table 1 is clear; there is a correlation between high industrial rates (relative to average rates) and a large share of bypass (relative to industrial sales). The ratio of industrial rates to average rates is the relevant measure of pricing policy because it reflects regionally varying cost opportunities. The ratio of bypass to industrial sales is the relevant measure of bypass because it normalizes for bypass opportunities.[1] Furthermore, a single snapshot characterization of relative rates and the self-generation decision fails to reflect long term expectations. The California data, for example, reflects a recognition by the California Public Utilities Commission (CPUC) back in 1986 that keeping industrial rates high would encourage self-generation. In a landmark decision

Table 1. Self-Generation Estimates by State

Utility Characteristics (1989)	Texas	New York	California
Capacity	60,400	31,200	44,200
Sales (billion kWh)	230	128	204
Industrial Sales	83	31	55
Average Price (cents/kWh)	5.7	8.9	8.5
Industrial Price	4.1	5.3	7.1
Industrial Price/Average Price	.72	.60	.83
Self-Generation			
Capacity (MW)	2,313	600	1,305
Production (billion kWh)	13.8	3.6	10
Bypass kWh/Industrial Sales	.167	.116	.182
Bypass kWh/Total Sales	0.60	.028	.049

on rate design, the CPUC reversed a decade-long policy by changing the industrial price for Pacific Gas and Electric from 95% of average rates to 81% (CPUC 1986). Despite this policy change, which was subsequently implemented for other utilities in the state as well, most bypass projects continue to operate.

While self-generation is the main form of bypass, transmission interconnection provides an alternative approach. This is the form bypass takes in the gas industry. A large customer builds his own connection to an interstate pipeline, bypassing the local distribution company. Attempts by retail electric customers to build their own transmission lines to out-of-service-territory utilities have so far failed (PAPUC 1984). On the other hand, the famous Geneva, Illinois case established the ability of municipalities buying wholesale power under FERC tariffs to obtain wheeling services from their former supplier when they choose bypass (Commonwealth Edison Company 1986). These two cases suggest that there is a rigid distinction between wholesale and retail wheeling. In practice, this distinction is malleable. A number of industrial firms have actively encouraged the small towns in which they operate to municipalize the local electricity distribution system. This has the effect of revoking the monopoly franchise on service held by the current supplier (typically an investor-owned utility). This municipalization bypass strategy is being promoted in a number of regions of the country. It is particularly strong in Ohio where liberal state franchise laws, favorable conditions for wheeling and considerable cost disparities among utilities all co-exist.

The bypass phenomenon is important for a number of reasons. First, it can have a considerable effect on the demand for a utility's service. Second, it poses an important constraint on a wide variety of actions by the utility. Because bypass is rate-induced, it will limit the ultimate penetration of large-scale DSM. One of the basic policy issues associated with DSM implementation is the trade-off between costs and rates (Hirst 1991). As DSM penetration increases, total social costs typically decline, but because sales decline as well, rates typically go up. Regulatory commissions and utilities can be expected to try to limit rate increases to potential bypassers. This will place the burden of DSM-related rate increases on captive customers. Finally, bypass through wheeling will be facilitated by expansions of transmission capacity and changes in policy regarding access. While utilities may need to make such expansions to facilitate resource acquisition strategies, they potentially increase the capability of customers to leave the system if these customers can obtain transmission access.

The Elusive Value Standard for DSM

As DSM activities have increased, it has become increasingly common to keep track of overall strategy for this activity by means of "conservation supply curves." These are essentially accounting devices that order perceived DSM opportunities by increasing cost. For effective comparisons, the conservation costs need to be converted from total dollar expenditures to annualized unit costs using some assumptions about appropriate discount rates, lifetimes and energy savings. The resulting plot can then be compared to various measures of alternative cost (also expressed in units of $/kWh) to determine an appropriate goal for the size of DSM programs in total. The three common standards of value commonly invoked in this process are: (1) retail rates, (2) long-run avoided costs, and (3) short-run avoided costs. Figure 1 illustrates generically what such curves look like, along with the alternative cost benchmarks.

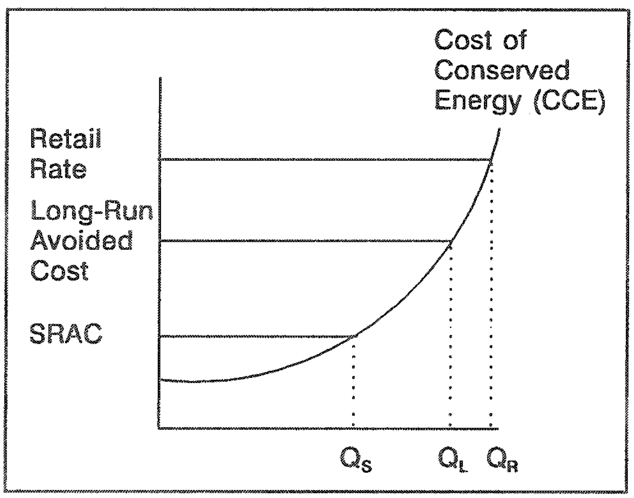

Figure 1. Conservation Supply Curves and the Standard of Value

Cost/benefit analysis of DSM is typically based on static avoided cost concepts (Krause and Eto 1988). The main challenges in applying these concepts to DSM programs involve the size of load impacts. When DSM has only a small impact on utility loads, then short-run valuation methods for avoided capacity and energy are straightforward to apply. The challenges all center on cases where DSM is large enough to alter the utility's supply plan; i.e., to defer or even cancel power plant construction that might otherwise have been necessary.

The ideal analytical solution to this problem would be to embed a DSM supply curve into a capacity expansion optimization framework. There have been several approximations made to this ideal approach (Hirst 1991; Ford, Bull and Naill 1987). The practical limitations on such efforts, however, are daunting. The most important issues involve limited DSM program data. The "conservation supply curves," as usually formulated, are only estimates of "technical potential" or "market potential," not how much can actually be achieved at a given price. A "DSM program supply curve" (note the different name) would need to represent the effect of various programs and delivery vehicles aggregated and adjusted for uncertainties. The uncertainties would include all the impact evaluation problems and technical innovation mysteries alluded to above. More practically, the usual *ceteris paribus* assumption never holds in the real world. Constantly changing developments in the electricity marketplace limit the believability of assumptions used to define the economic background of any "optimized" scenario.

A practical illustration of the problem posed for valuing large-scale DSM is the recent debate on long-run avoided cost in New York (NYPP 1991; NYPSC 1991). Conditions in New York are unique due to the presence of lucrative standard offer contracts to Qualifying Facilities (QFs). While there is considerable uncertainty about how much capacity will be developed under these contracts, it could be equal to at least 25% of existing capacity, or more. At the same time, the utilities, under direction from the regulatory commission, are implementing large scale DSM. If all of these resources develop, none of them will be worth much to the ratepayers because of massive excess capacity.

Excess capacity lowers avoided cost through two separate mechanisms. First, it pushes back further into the future the estimated date at which new capacity will be needed. This means that the long-run component of avoided cost has lower present-value because it is discounted more. In the limit, of course, the long-run never comes. The second effect is a depressed level of short-run avoided cost. Qualifying Facilities are treated by utility dispatchers as "must-run" resources, unless they have agreed to some dispatchability contractually. A "must-run" resource has the effect of lowering system marginal cost because it effectively raises all other units to higher positions in the loading order. Therefore, baseload resources end up serving intermediate loads, and intermediate load resources become peakers. In some cases, hydro and nuclear based power must be dumped onto the economy sale market. Figure 2 illustrates this dynamic. This Figure is based on simulations made by the New York Power Pool (NYPP 1991). The point labelled "B+12%" (Base need plus 12% incremental QF or DSM) corresponds primarily to the first effect, delay of the need for new

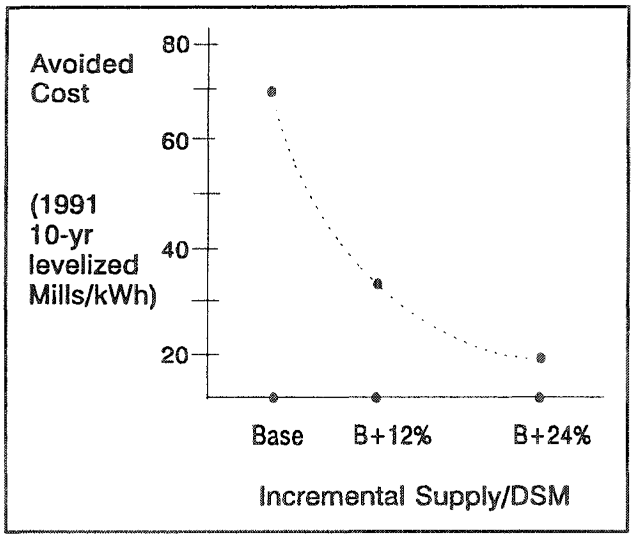

Figure 2. Avoided Cost as a Function of DSM/QF Supply

capacity. The point labelled "B+24%" corresponds primarily to the second effect, depression of short-run avoided cost.

Given the dynamic illustrated in Figure 2, how is the cost effectiveness of DSM programs to be measured? If the value is set too high, then so much DSM gets developed it ends up being worth less than estimated. Conversely, if the value is set too low, too little DSM will be developed. Grappling with this problem is generic for all large-scale DSM activity. The New York context is even more complex due to the role played by the standard offer contracts for Qualifying Facilities.

Abundance or Scarcity?

The preceding examples are basically variations on the theme of abundance. They emphasize the potential for excess capacity. There are other reasons to believe that the current planning problem is essentially one of managing the plethora of alternatives. Two purely supply-side options which also underline this theme are important to mention. One is the private power industry. By any measure, this industry has exceeded the wildest expectations of the authors of the PURPA legislation. In several states, power produced under private ownership has more than 10% of the total market. Forecasts of the share that this segment will have of the new generation market for new capacity start at a low of 30% (RDC 1990). The other supply-side opportunity of major proportions is the re-powering potential of aging fossil-fired utility boilers. By 1995, roughly 25% of all capacity will be fossil-fired steam turbines that are more than 30 years old. These have the potential to be re-powered with either coal or gas at low incremental capital cost, much higher efficiency and much lower emissions than their predecessors. Further, they raise many fewer siting and permitting complications than new "greenfield" construction. Finally, most of these sites are located at favorable spots in the transmission network and have well-developed fuel delivery infrastructure. Utilities are just beginning to tap the very large potential for these re-powering projects.

If there are so many alternatives, has the era of scarcity passed without our quite recognizing it? Clearly that would be over-stating the case. There are still important and costly constraints in the electricity system. Transmission capacity is scarce, and new lines are difficult to build. Operational inflexibilities in the power system have gotten more binding with the decline in load factors and the increase in non-curtailable generation (Le et al. 1990). Furthermore, within the broad range of available alternatives, there are few which are very low cost. This is true even of DSM, where the lesson from large-scale programs is that overhead, administration, verification and other delivery mechanism costs can approximate in magnitude the technology cost (Joskow and Marron 1991).

The implication of this mixed picture is that there are many ways to meet incremental service demand. The cost differences in many cases are not enormous, but key constraints on implementation may make for substantial differences. The lesson from this survey is that there is a very competitive battle for market share. The interests represented by the resource alternatives will struggle with and through the regulatory system to capture their share of the market. With this in mind, we turn to consider how the planning process ends up with market share allocations.

Allocation Rules: Explicit and De Facto

It is useful the evaluate the procedures used in integrated resource planning by the results that emerge. This perspective helps to illustrate both the strengths and weaknesses of particular planning processes as well as the strategic issues that will ultimately face regulators. The analytic framework adopted in this discussion is primarily based on political economy. The economic interests of actors are given primacy over the intellectual language in which various positions are argued. For conceptual convenience, we rely on generic and typical outcomes rather than exhaustive detail. Figure 3 shows a typology of four allocation models. We will discuss each of them and loosely characterize the regulatory regimes to which they correspond.

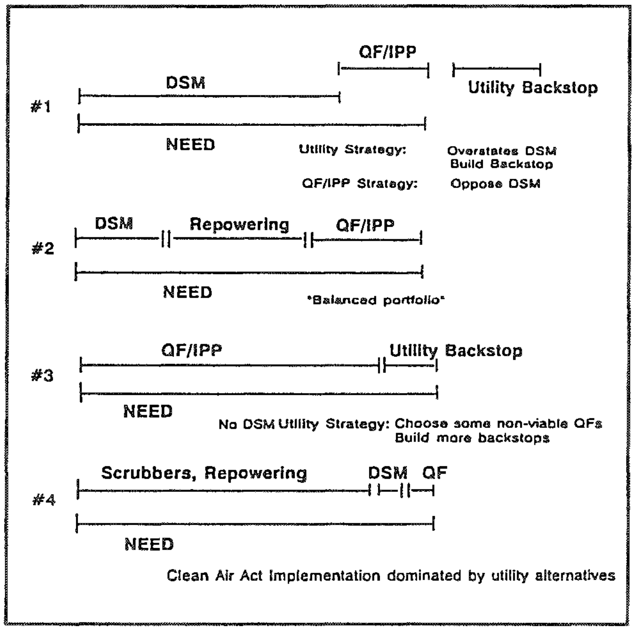

Figure 3. Alternative Models of Resource Allocation

DSM Maximalism

Model #1 in Figure 3 represents a DSM maximalist perspective. The intellectual rationale for this strategy is that DSM represents the least-cost resource alternative, and its use should be maximized for greatest social benefit. Other factors determine such outcomes as well. Most prominent is utility shareholder incentives. The opportunity to increase earnings from what would otherwise be a cost pass-through activity is certain to attract the attention of utility management and induce them to co-operate with external constituencies advocating large-scale DSM. Two of the states that most nearly approximate this model, New York and California, have adopted shareholder incentives for DSM activities for all investor-owned utilities (Barakat and Chamberlin 1991). In these states, the explicit commitment to DSM by utilities and regulatory agencies is large. The California Energy Commission's *Electricity Report 90* assumes that 70% of incremental need over the twelve year planning period will come from DSM, a good fraction of which is "uncommitted." In New York, roughly the same goals have been adopted by the State Energy Office (NYSEO 1989) and The New York Public Service Commission Staff (NYPSC 1991).

Model #1 can be expected to produce strategic responses, and to be perceived differently by the parties involved. As Figure 3 indicates, the private power industry has a reduced market share under this model. In California, Qualifying Facilities have dominated the capacity additions during the 1980s. Model #1 would reduce their role substantially. In New York, Qualifying Facilities are just beginning to experience the explosive growth that took place earlier in California. The State Energy Plan would limit that growth. Trade associations representing the private power industry have already begun to question the major commitment to DSM. One of their representatives has recently argued to the state legislature that the utilities' commitment to DSM is just a way of forcing QFs out of the market and preparing their own re-entry when the "uncommitted" DSM fails to materialize (Smutney-Jones 1992). Similar opposition to DSM maximalism is also appearing in New York (Murphy and Breidenbaugh 1992).

Balanced Portfolio

Model #2 in Figure 3 represents a balanced portfolio approach. No single resource plays a dominant role. The integrated resource plans of the two major investor-owned utilities in Florida, Florida Power and Florida Power and Light, are the best representatives of the balanced portfolio approach. These plans have a good deal in common at the strategic level, although they differ considerably in detail.

In both cases, the plans assert that DSM is a favored resource, but its share of incremental need is 20-30%. There is considerable attention paid to the balance between utility construction and competitive power purchases. Each utility argues for the unique opportunities represented by its own construction projects that are not replicable by other suppliers. Florida Power and Light proposed re-powering existing oil-fired steam units into gas-fired combined cycle. The advantages argued for this option include the usual list of re-powering features: (1) use of existing sites, (2) location near load centers, and (3) ease of integration with the transmission network (Florida Power and Light 1989). Florida Power proposed the construction of new gas-fired combined cycle capacity. The principal strategic advantages cited for these units were: (1) the expansion of gas pipeline infrastructure in Florida facilitated by the project, and (2) avoidance of negative financial consequences from excessive reliance on purchased power (Florida Power 1991).

These arguments and their resolution have important consequences for the role of competitive bidding for new generating capacity. First, it is clear that the utility is competing with the private power industry for market share. This competition, however, does not take the form of an explicit auction in which the actors meet on a "level playing field." Rather, the case is made administratively that the differentiating advantages of utility construction cannot be matched by competitive suppliers. Many of the strategic arguments used to support this case are difficult, although not impossible, to quantify. If these advantages were to be weighed in an explicit bidding system administered by the utility, it would be difficult to avoid the perception that self-dealing influenced the outcome. Alternatively, if the regulatory authorities were to administer such an explicit competition, the analytical burden would require a significant use of resources, many of which would ultimately duplicate utility capabilities.

The adopted solution, acceptance of the utility proposals with residual demand allocated to competitive procurement, recognizes the qualitative and strategic nature of the issues without the apparatus of explicit quantification of all argued issues. This solution rejects the all-sources bidding approach, and implicitly accepts the notion that market share issues are best resolved administratively, at least at this stage of market development.

Market Maximalism

Model #3 in Figure 3 represents a polar opposite of Model #1, with private power playing the role of DSM as the dominant resource. This model corresponds most closely to Virginia, although there are also strong resemblances to Texas. As in the case of model #1, the market share domination tends to induce strategic responses. The main interaction that is identifiable in this case involves the viability of private power projects and the role of utility construction as a backstop in the event of private power development failures.

While no one is asserting that Virginia Power manipulated its bidding program, it is clearly the case that a significant amount of capacity was selected in its large 1988 solicitation which was located in transmission constrained areas and subsequently failed to develop. Losing bidders, including one sponsoring a relatively higher cost project near load centers, have argued that Virginia Power could have provided "clearer communications," and may have failed to assess development and wheeling risks properly (Electric Utility Week 1989). It is also the case that Virginia Power did announce its intention to participate as a joint venturer in a utility construction project after the failure of the remotely sited projects became apparent (Ellis 1989). Thus, in effect, lack of QF viability did facilitate utility backstop construction.

The net result of failures in competitive bidding is likely to be increased market share for regulated utility construction. This fact cannot have been lost upon utility management, and should serve as a cautionary note regarding regulatory enthusiasm for complete reliance on market forces to satisfy incremental need requirements to the exclusion of all other options. A successful competitive bidding regime requires a good deal of sophistication on the buyer's part to develop the analytical capability to trade-off the various risks and attributes of private power projects. There are formidable problems involved (Kahn et al. 1989, 1990). These problems are best tackled if the utility does not also have significant market share conflicts with private suppliers.

Minimal Alternatives

Finally, model #4 represents the closest to a "business-as-usual" resource allocation. The definition of business as usual is that DSM and private power alternatives play only a small marginal role in the satisfaction of need. However, in this case, what constitutes utility investment is often not standard powerplant construction. Most regions where model #4 would apply are heavily impacted by 1990 Clean Air Act (CAA) Amendments. Therefore, the need facing these utilities involves compliance strategies. It is generally true that DSM and power purchases play a relatively small role in these strategies.

It is likely that utilities pursuing the general approach of model #4 will come under pressure from various constituencies advocating a larger role for alternatives. It is largely as a result of such pressures that models #1-#3 have come about. The special circumstances associated with CAA compliance are unlikely to deflect these pressures completely. Therefore, it may be best to think of model #4 as a pre-condition for the evolution into one of the other patterns. If this is the case, then it is useful to examine what conditions leads to models #1-#3. We turn to this subject next by exploring extreme versions of two of these models, which we call the supplier of last resort function.

The Utility As a Supplier of Last Resort

Models #1 and #3 both have in common a severely reduced role for traditional utility investment in new generating capacity. The rationale for these reductions are indeed radically opposite in the two cases. Large-scale DSM is a new monopoly franchise for the utility, and its case is argued in terms of market failure on the demand-side. Maximal market competition is a logical consequence of the proposition that natural monopoly conditions no longer exist in bulk power generation, and therefore competition should replace it. Both of these positions are mythologies which ignore the very substantial costs associated with allocating the dominant role to one resource.

The extreme consequence of models #1 and #3 is the liquidation of the asset base of the regulated utility. This is not a costless process. As utility investments decline, there are fewer assets from which they can produce earnings. One important consequence that both large-scale DSM and aggressive power purchasing strategies can impose is financial deterioration, and a resulting higher cost of capital for the firm's remaining businesses. The Florida Power plan cited above invoked this issue as part of its argument in favor of a utility construction program. Conversely, Virginia Power, one of the largest buyers of private power, has had its bonds down-graded in part because of reliance on this resource (Electric Utility Week 1991).

The basic financial problem facing electric utilities under either of the "maximalist" allocation rules is that liabilities are implicitly increased more than earnings, therefore the effective interest-coverage ratios decline. Both DSM and private power purchases involve contingent liabilities for the utility. In the DSM market, there may be unanticipated costs due to unexpectedly high customer response or program cost increases. If the regulators dis-allow some of these costs, earnings will suffer. In the private power market, long-term capacity contracts may also have contingent liability features which makes them partially equivalent to debt. In this case, the utility's interest-coverage ratios decrease, which means lower bond ratings and higher cost of capital (Moulton 1991). These effects can be offset by shareholder incentives for DSM, which are already in use, and for private power purchases, which are not used to date. It is not clear how stable a source of earnings such incentives might ever become.

In addition to the financial problems caused by "maximalist" allocation rules, there are potentially large rate consequences, particularly from large-scale DSM. These have competitive impacts which can be de-stabilizing for the utility. The magnitude of the rate effect from DSM depends critically on the size of the program and its costs. We illustrate these effects through simple numerical examples in Table 2. In this Table, we imagine a utility selling 10 MWh, with costs of $700, and therefore average rates of $70/MWh. The incremental need over the planning period is 3 MWh (equal to 2.2% growth over 12 years). The resource options are DSM at $40/MWh or supply at $60/MWh. Clearly, the "least cost" option is DSM, although rates go up 17% (1.17 = 82/70) compared to the starting point, and are more than 20% higher than the supply-side option (1.20 = 82/68).[2]

Table 2 also shows what happens under various unfavorable market outcomes. One outcome of interest is higher than expected DSM costs. Suppose they turn out to be 50% above expectations. Then this alternative is no longer less expensive than supply, and rate impacts go to 25% above the starting point and nearly 30% higher than the supply only path. Of course, there are environmental benefits of DSM which are not counted here.

Next, imagine what happens when anticipation of the DSM rate impacts, or the sheer orneriness of large customers induces bypass. For simplicity, we assume that the bypassers leave instantly, lowering existing system sales to 9 MWh and costs to $660, thereby raising rates to $73/MWh. The planning process may be either fast or slow to recognize this change and adapt. The next case assumes that it is fast. This means that "need" has been adjusted downward to only 2 MWh because the system can now serve an additional 1 MWh at a cost of only $40. In this case, rates rise under the DSM scenarios and fall under the supply-only scenario, but in a more modulated fashion than before. Since system rates go up immediately under bypass, the DSM induced rate increase is only 12-18% compared to the starting point, and 15-20% compared to the supply-only plan, depending on the DSM cost.

More serious consequences follow from failure to recognize the bypass induced load change, and the planning process still acquires 3 MWh of new resources. In this case, even the low-cost DSM outcome raises rates by 20%, and the high cost case by 27% compared to the starting point. The supply-only case also raises rates by 4%, since excess capacity is being acquired. The cost errors in these cases are the same level as the cost differences separating the low-cost DSM cases from the higher cost supply-only plans. This means that choosing the "right" resource is no more important (and could even be less important) than choosing the right amount of resources.

These examples illustrate the large impact that planning errors can have on rates, the magnitude of rate impacts from large-scale DSM, and the unstable competitive position of the utility. These scenarios resemble the "spiral of impossibility" problem that was thought to threaten electric utilities from their unmanageable nuclear power programs of the late 1970s and early 1980s. In fact, rigidities of any kind in the planning process can introduce instabilities. The competitive situation created by DSM induced rate impacts and increased bypass opportunities is arguably worse than the earlier period, when customers had fewer choices. Although none of today's resource options are quite as large and indigestible as the period in which 1000 MW resource additions were standard.

Table 2. Costs vs. Rates

		DSM @ $40/MWh	DSM @ $60/MWh	Supply @ $60/MWh
Base System		Need = 3 MWh		
Sales (MWh)	10	10	10	13
Costs ($)	700	82	88	88
Rates ($/MW)	70	82	88	68
Bypass Case - Fast Adaption		Need = 2 MWh		
Sales	9	9	9	11
Costs	660	740	780	780
Rates	73	82	86	71
Bypass Case - No Adaptation		Need = 3 MWh		
Sales		9	9	11
Costs		780	840	840
Rates		87	93	76

These admittedly extreme examples emphasize rate effects because the percentage changes are larger than the percentage cost changes, and they interact with bypass. The potential bypass customer does not care about the total social cost of energy services; the customer cares about rates. Furthermore, it will be difficult to contain the forces that will lead to increased wheeling, including at the retail level. This competitive reality will limit the ability and willingness of utility management to pursue large-scale DSM, even with shareholder incentives.

Conclusion: The Value of Stability

How then should regulators, utility management and the external constituencies who participate in the planning process think about the balance between market forces and other planning objectives? A few simple conclusions emerge from this discussion.

First, there are potential dis-economies of scale in maximalist DSM programs. Diminishing returns from marketing to "hard-to-reach" customers can raise costs to the point where DSM, at least from the monetary perspective, is no longer noticeably less expensive than other options. In addition to these static dis-economies, the deterioration in the financial and competitive position of the vertically integrated utility is not a cost that is easily borne or pushed into the background.

This argues for balanced portfolios as an explicit objective of the planning process. Limiting DSM to the region of the cost curve where economies are more certain can help to preserve its role as a "least cost" resource. A reasonable share of new supply allocated to private power producers can limit the financial pressures of utility construction that proved so onerous during the 1970s and early 1980s. Conversely, a reasonable amount of utility construction will prevent deterioration of the asset base and draw on unique resources such as re-powering. Exactly how the balancing act gets worked out in practice is, of course, the delicate job of all participants. The important point to remember, however, is that there is no monopoly on preferred resources; that balance is always an objective on the overall planning process.

Finally, there is no prescription to avoid planning errors. Mistakes will be made, and some allowance for this is desirable. Here the important attribute is flexibility. It used to be argued that DSM and private power offered such planning flexibility. More recent experience should be sobering. DSM programs have an inertia of their own. Private power development can lead to excesses. It is important, therefore, to think of building flexibility options into the resource planning and acquisition process. Modular construction programs, deferral options in private power contracts and similar management tools need more systematic exploration and implementation.

The challenge of integrated resource planning is managing diversity. Competitive pressures provide a brake on any one of the resource options. While this may seem to multiply the constraints, it is probably constructive in the long run.

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Endnotes

1. Thus, although Texas has the lowest industrial rates and the highest amount of bypass. These reflect its low resource costs (i.e., cheap natural gas) and substantial industrial base (petrochemical industries). On a relative basis, however, New York has lower rates and California has greater bypass.

2. These rate impacts are greater than those in Hirst (1991) because all of incremental need is being met with DSM, not just 35-40%, and therefore DSM costs are greater.

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