The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities

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The electric industry's move towards unbundling of the competitive generation and merchant functions from the monopolistic transmission-and-distribution functions has raised questions about the future of integrated, least-cost resource planning. However, the economic benefits of integrated planning and of demand-side management will persist in a restructured market; retaining them need not interfere with increased competition.

In this paper, the authors describe opportunities for IRP and DSM by regulated distribution utilities in a market where unbundled generation companies compete. These opportunities include planning on an integrated basis and assembling the portfolio of distribution resources that minimizes the cost of meetings customers demand for distribution services. In addition, there will likely be continuing opportunities for investment by the distribution utility in customer efficiency improvements. Market barriers to customer investment in energy conservation will persist in a competitive market, and energy-service companies will face the same barriers to entry that today prevent them from providing comprehensive efficiency services to any but the largest customers. If so, distribution utilities will need to intervene in the market with DSM programs to acquire the customer-efficiency improvements called for in their distribution-system IRPs.

The likelihood, and the scope, of such a role for distributed-utility IRP and DSM will depend on regulators' commitment to, and on political support for, a restructured model that maintains the economic benefits available through the integrated-resource-planning process.

INTRODUCTION

Two major paradigm shifts have dominated electric-utility planning over the past decade. In the mid-1980s, integrated resource planning (IRP) shifted the focus of utility planning from the utility's side to the customer's side of the meter. Where the traditional approach sought to minimize the cost to the utility of serving customer load with electricity generation, integrated resource planning entailed minimizing the cost to ratepayers and society of meeting customer demand for energy services.

The advent of the IRP paradigm consequently broadened the scope of the utility planning process to include the following:[1]

- developing resource plans for acquiring the mix of generation (construction, retirement, repowering, purchases, purchase options, etc.), transmission and distribution (expansion, efficiency, and distributed generation), and demand-side management (DSM) (efficiency and load management) options that minimize costs to ratepayers and society;
- implementing DSM programs for overcoming market barriers to customer investment in energy efficiency and renewable end-use technologies;
- minimizing and balancing risks, especially those related to the costs of new construction or fuel prices;
- reflecting environmental concerns;
- facilitating technical change (such as renewable and other relatively clean generation technologies);
- achieving related social goals, such as assisting low-income customers and promoting of economic development.

Utility planning is currently undergoing a second paradigm shift, as the vertically integrated utility industry moves toward unbundling of the competitive generation and merchant functions from the monopolistic T&D functions. Not surprisingly, the question of the mechanics of market restructuring has so far distracted attention from that of the effect of restructuring on utility resource planning and, in particular, of the role of IRP and utility-investment DSM programs in a competitive market. Instead, some regulators and other observers have assumed that opening up the market to retail competition will ultimately obviate the need for IRP and utility DSM investments, while acknowledging the need for and benefits of continued IRP efforts during the transition. Others have asserted that IRP efforts stifle competition and therefore should be dismantled or dramatically scaled back as part of the restructuring process.

To the contrary, we suggest that a closer examination of the restructuring process and likely outcomes indicates continuing, but more focused, opportunities in a competitive market for economic gains with IRP and DSM programs. As we discuss in this paper, we expect regulators to continue requiring distribution utilities to minimize the cost to customers and society of distribution services. Distribution utilities will therefore continue planning on an integrated basis, assembling the portfolio of distribution resources (such as distribution-capacity upgrades, loss-reduction investments, system reliability and quality improvements, and targeted improvements to customer efficiency) that minimizes the cost of meeting customers' demand for distribution services.

There likely will be continuing opportunities for distribution-utility investment in customer efficiency improvements for the same reasons as under today's regulated-utility regime: market barriers to customer investment in conservation will persist in a competitive market, and retail-service companies are likely to face the same barriers to market entry that prevent today's energy-service companies from providing a wide range of efficiency services to any but the largest of customers. If so, there will be an opportunity for distribution utilities to intervene in the market with DSM programs to acquire the customer efficiency improvements called for in their distribution-system IRPs.

Beyond planning and investment in DSM that minimizes the cost to customers for distribution service, we believe that the rationale for utility investment in DSM that minimizes the cost of total energy service (generation, transmission, and distribution) remains as strong for the restructured distribution function as it was for the integrated utility. Just as the market is unlikely to invest in all efficiency resources economically justified on the basis of distribution-service benefits, the market is likely to fall short on the basis of total energy-service benefits. If so, the opportunity for additional economic gain would argue for DSM investment by the distribution utility (or appropriate state or regional agency) that reduces the costs of generation and transmission services, even though the distribution utility would not be responsible for procuring such services for its customers. The likelihood of such an expanded role for distribution utilities will depend on regulators' commitment to, and the political support for, a restructuring model that maintains the economic benefits garnered through the IRP process.

Integrated-planning and DSM efforts may continue after restructuring, but they are likely to be formulated and implemented in new ways to reflect the onset of market competition. As we discuss in this paper, the role of market forces are likely to be reflected in economic evaluation techniques, implementation strategies, and funding mechanisms for distribution-utility DSM programs.

THE DISTRIBUTION UTILITY OF THE FUTURE

The structure of the electric-utility industry is undergoing a radical reformulation as regulators, utilities, and the public craft strategies for unbundling the generation, transmission, distribution, and merchant functions of vertically integrated utilities and for reforming the regulatory framework. While the details vary by jurisdiction, restructuring proposals generally foresee the distribution function remaining a geographic monopoly, the transmission grid operated by regional entities, and generation and merchant services provided in a competitive market (e.g., California PUC [1996], Massachusetts DPU [1996], New York DPS [1995]). These proposals also assume generation will be centrally dispatched through a regional pool run by an independent system operator, with the pricing of generation services to retail customers determined by some combination of the spot price in the regional pool, power-supply contracts, and other financial instruments.

Most models of the restructured industry would give the distribution utility one of two roles in power supply: either it would buy power at market prices from the pool (or a combination of purchases from the pool and from generators), or it would be a common carrier for customers, who would directly purchase bulk power from competitive marketers. In either role, the distributor would be responsible for operating, maintaining, and upgrading the equipment on the distribution system, and perhaps for providing metering and billing services.

A CONTINUING ROLE FOR DISTRIBUTION-UTILITY IRP

With attention focused on mechanics of market restructuring, most proposals have not fully developed the framework for regulating distribution utilities. Nor have such proposals delineated the full scope of distribution services to be required from distribution utilities, especially with regard to the role of IRP and utility DSM programs in competitive markets. In most cases, the treatment of these issues is confined to:

- establishing performance-based ratemaking (PBR) for providing financial incentives to distribution utilities to engage in IRP in place of the heavy hand of regulatory mandates;[2]

- committing to the continued implementation of utility DSM programs, at least during the transition to competition.

Although these proposals address the IRP and DSM issues only cursorily, there is wide agreement among these proposals that

- distribution utilities will continue to be required to minimize the cost of distribution services provided to customers;[3]

- economic gains are achieved by minimizing the total cost to customers (and society) of utility services, not just utility spending on such services.[4]

Consequently, distribution utilities are likely to face regulatory obligations and economic motivations to engage in integrated planning and acquisition of resources on both sides of the customer's meter similar to those faced by vertically integrated utilities. Required to minimize customer costs, utilities will seek to assemble the least-cost portfolio of distribution ''supply'' and efficiency resources from the available options. To the extent that customers fail to invest in efficiency improvements that are cheaper than supply alternatives, distribution utilities will invest in those efficiency upgrades through their own DSM programs.

The scope of the distribution utility's IRP and DSM responsibilities will depend on how broadly regulators define the utility's obligation to minimize its customers' costs. At a minimum, regulators are likely to require utilities to plan and invest in DSM that minimizes the cost of distribution services. In this case, distribution utilities could invest in customer efficiency improvements that the market fails to capture to the extent economically justified on the basis of distribution-service benefits.[5]

Regulators could assign distribution utilities a greater role, requiring them to invest in DSM to minimize total energy-service (generation, transmission, and distribution) costs.[6] In essence, the distribution utility would take on the DSM obligations formerly carried out by its vertically integrated predecessor: to invest in efficiency left untapped by market forces that is less expensive than the total cost of generation, transmission, and distribution avoided by the efficiency investment. Without such an expanded obligation, the distribution utility may forego investing in savings from resources that are cost-effective in terms of total energy service, but that cannot be justified solely on the basis of distribution benefits. If so, restructuring may entail an economic loss as customers bear higher costs for energy services under competition than would have been incurred under the current IRP structure.[7]

Regardless of the scope of the distribution utility's obligations, there are several reasons for continuing the IRP and DSM functions. First, there will be a wide range of options available to reduce utility and customer distribution-service costs, including

- loss-reduction investments, such as larger conductors, low-loss transformers, and improved system configurations;

- improvements in distribution-system reliability and service quality that are less costly than customer investments to compensate for lower levels of service quality;

- investments in customer-efficiency improvements;

- investments in distributed-generation resources (such as photovoltaics at the end of summer-peaking feeders, or fuel cells on customers' premises).

These options are all closely associated with, if not intrinsic to, the distribution system. Some of these activities may be pursued in part by other parties (as energy efficiency and customer generation are today), but maximizing their benefits requires that they be targeted to areas and times in which they are most valuable to the distribution system, not necessarily to individual customers.

Moreover, the geographically specific interaction of investments in distribution capacity, delivery-system reliability, power quality, and efficiency, customer efficiency, and distributed generation cannot be optimized without some form of coordinated planning. Since the distribution utility will be the entity with primary responsibility for maintaining and expanding distribution efficiency and capacity, as well as largely responsible for service quality, it is the logical nexus for planning all distributed resources.

Second, the widely-recognized market barriers to customer investment in efficiency—lack of capital, time, and information; risk aversion; and split responsibilities and incentives—will persist after restructuring. To the extent that market forces are unable to overcome such barriers, there will be opportunities for distribution-utility investment in customer efficiency improvements.

Third, market mechanisms for overcoming the market barriers faced by small customers are not likely to develop anytime soon. Energy-service providers will continue to face familiar limits in serving small customers.[8] The transaction and information costs for small customers and providers (such as bidding, contracting, verifying installation quality, and measuring savings) will continue to limit the attractiveness of efficiency services in the competitive market. The risks and costs associated with cost recovery through guaranteed-savings or shared-savings arrangements will limit providers to the quickest-payback, highest-margin efficiency investments.[9]

Finally, even where market mechanisms emerge for effectively overcoming market barriers, efficiency investments will fall short of the level justified by societal benefits, since the market will not generally value societal benefits (including reduced uncertainty and environmental effects) beyond those that are reflected in prices.[10]

Restructuring may create additional incentives for distribution utilities to engage in IRP and DSM-program implementation. Distribution utilities may find DSM and distributed generation to be attractive opportunities to increase investment and return, support the distribution system, avoid contention over the siting of transmission and major distribution facilities, improve service quality, and attract and retain load in the service territory.[11]

Compared to the existing integrated utilities, distributors will face reduced disincentives to pursue energy efficiency (and distributed generation). Since they will not be saddled with generation costs (and the generating assets will be repriced at the market value), the distributors will face lower lost revenues than the integrated utilities.[12] With unbundling of service, the distribution companies will be freed of the dominance of central supply resources in integrated utility planning.

IRP FUNCTIONS OF THE DISTRIBUTION UTILITY

As discussed above, after restructuring, distributors are likely to remain responsible for acquiring a least-cost portfolio of distribution system improvements, efficiency, and distributed generation. Integrated resource planning in a competitive market would entail the following:

- Projecting market prices for generation capacity and energy, whether these costs flow through the distributor or are paid directly by consumers.
- Forecasting pool transmission rates.
- Estimating avoidable distribution costs, both for the system as a whole and for local areas.
- Implementing a mix of distribution-capacity expansion, distribution-system loss-reduction investments, distribution-system reliability and quality improvements, comprehensive DSM, and distributed generation to minimize customer costs.
- Possibly undertaking efforts to assist low-income customers and promote economic development.[13]

The relevance of market prices for generation and pool transmission rates to the IRP process will depend on the scope of the distribution utility's responsibilities for minimizing customer costs. As discussed above, if the distribution utility is required to minimize the cost of distribution services only, an integrated plan would include all customer-efficiency resources that cost less than customers' avoided distribution-service costs: distribution system costs, generation and transmission values of line losses, and customer costs for power quality and reliability. In addition, the distribution utility could invest in any DSM that costs less than its avoided generation, transmission, and distribution costs, as long as the utility could recover from customers a large enough share of the DSM cost to reduce the utility's investment to below the amount justified by distribution benefits.

If the distribution utility's obligation encompasses minimizing customers' total energy-service costs, then all generation and transmission benefits will be directly relevant to the determination of the extent of the DSM investment included in an integrated plan. In this case, the plan could include all DSM resources economically justified on the basis of combined generation, transmission, and distribution benefits.

In either case, DSM actions by the distribution utility will reduce generation and transmission costs ultimately borne by its customers. As such, these reductions in customer payments are properly included as avoidable costs when evaluating resources from a customer- and total-resource-cost perspective.

The following sections discuss the IRP functions likely to be undertaken by distribution utilities in a competitive environment, focusing on those aspects most important to the design and implementation of energy-efficiency programs.

Market Prices for Generation Capacity

Utilities have typically estimated avoided costs on a stand-alone basis, considering only the running costs of their own plants and the costs of the plants it intends to build, with little or no recognition of market values of purchases and sales.[14] Even so, many utilities have included projections of the availability and cost of off-system economy power purchases. More recently, some estimates of utility avoided costs have recognized that regional power-supply balances will determine both the resale value of surplus capacity and energy and the cost of purchasing additional power supplies.

These estimates use projections of regional market prices as inputs to their avoided-cost computations.[15]

In a competitive generation market, avoided generation costs would be projected by the distribution utility and its regulator in much the same fashion that fuel prices and purchased power have traditionally been projected. These projections would be no more uncertain than present utility-specific projections of dispatch prices and need for power; indeed, the regional estimates should be less volatile, since events that may have significant effects on a single utility (loss of a major unit, a local building boom) are likely to be less important on a regional scale.

Each state (perhaps with input from the regional power pool or transmission company) might prepare a single long-range forecast of market energy and capacity prices, to be used by each distribution company in rate design and planning DSM, distributed generation, and any power-supply obligations the distributors undertake.

Pool Transmission Rates

Charges from the transmission pool may be paid by the distributor, the marketer, or conceivably directly by the consumer. Just as for generation, transmission costs are ultimately paid by consumers and are avoidable by actions of the distributor.

Avoided load-related transmission costs can be determined at the level of the transmission company, where they can be subject to regulatory review.[16] The distribution company and its regulator can either accept this estimate (which will be easier if the transmission company is a quasi-public entity, rather than a consortium of generators or distributors), or modify it. Given the long lead times for major transmission projects, avoidable costs can be estimated from projections of additions and load growth (NARUC 1992, 127–135).

Minimizing the private cost of the distributors' customers would require the distributor to value transmission at the variable portion of transmission rates. Minimizing total public costs over the area served by the transmission pool would require the use of marginal transmission costs. To eliminate this tension, the marginal transmission rate should approximate avoided cost. This can be achieved by the use of a tiered rate (as used in the New England Electric System's current wholesale rates to its retail subsidiaries, and in some rates of the Bonneville Power Administration), with the higher-use block set at avoided cost.

Avoidable Distribution Costs

Avoided distribution costs can be estimated for the distribution-utility's service territory as a whole, and for specific areas.

System-Wide Costs. Some distribution-utility actions will have effects on load spread throughout the service territory, including

- rate design,
- load control available to all customers,
- some classes of DSM programs, such as market transformation and most lost-opportunity programs, except where standards and rebates can be evaluated on a site-specific basis,
- changes in distribution-equipment-purchase standards, such as the types of transformers to be stocked.

System-wide avoided-cost estimates are also relevant for costs that cannot be disaggregated geographically, such as

- *Wear and tear.* The lives of transformers and lines (especially underground lines) are usually limited by the number of hours in which they operate at high loads. The heat buildup associated with heavy loading result in deterioration of insulation and eventual failure (Chernick, Plunkett, and Wallach 1993, 68–83).
- *Lower-level equipment.* While transmission lines, substations, and feeders are planned on an individual basis to meet area loads, the rest of the equipment between the feeder and the customer—primary taps or laterals, line transformers, secondary lines, and services, as well as such associated equipment as capacitors and voltage regulators—is generally reinforced or replaced as need arises. The area that contributes to the failure or overloading of this equipment—one customer for a service, several for a transformer, a few hundred for a lateral—is usually too small to allow for detailed planning.

Estimating system-wide avoided distribution costs should be very similar to current practice, although distributors may be able to concentrate on improving avoided-distribution estimates more effectively than the existing integrated utilities.[17] Like generation and transmission capacity costs, these average avoidable system-wide distribution costs can be expressed in dollars per kilowatt-year (kW-yr.) for screening alternative resources.

Local Area Costs. In the course of planning its delivery system, the distribution utility will continue to identify areas in which transmission lines, substations, or feeders are expected to become overloaded in the future.[18] This planning generally considers the adequacy of voltage levels at the ends of feeders, the adequacy of capacity at peak load with all equipment in service, and the adequacy of capacity with a single component out of service (a *first contingency)*. New equipment is added only when the anticipated problem cannot be avoided by reconfiguring load: changing the portion of each feeder served by various transformers or substations, changing the primary laterals served by each feeder, and changing the switching pattern in the event of a first contingency.

Unlike other avoidable capacity costs, major distribution additions are geographically diverse, time-dependent, and discontinuous. A certain level of load reduction in a given area by a particular date—for example, 6 MW by 2001—will allow deferral of the addition by one year, for a large present-value saving (say, $300,000); a larger addition by the next year (7 MW by 2002) will allow deferral for two years (savings nearly $600,000), and so on.[19] These avoided costs cannot be usefully converted to dollars per kW or per kW-yr. for screening of alternatives, since the value of a kW of load reduction depends on what other reductions can be obtained. In this example, the first kW, or the 2,000th kW, has no value, but the 6,000th kW in 2001 is worth $300,000. Rather than attempting to unitize the cost reduction into dollars-per-kW or -per-kW-yr. terms, the distribution utility will be better served by determining the value of deferring the addition by various numbers of years, and seeking packages of resources that produce the necessary load reductions at a net cost lower than that value.[20]

For many planned-distribution capacity additions, the area in which load reductions can contribute to deferring the addition will be much larger than the area served directly by the new equipment, or by the critically-stressed existing equipment. Reductions on other circuits will allow normal or contingency loads to be shifted to those circuits, deferring the need for the addition.

Planning and Implementing DSM

Current DSM planning is evolving toward a two-track system, which will continue to make sense after restructuring:

- *General DSM,* concentrating on lost opportunities, market transformation, social objectives (low-income assistance, economic development), and other programs that are efficiently operated on a system-wide basis.

- *Targeted DSM,* implementing retrofit programs in T&D-constrained areas, and maintaining the capability to ramp up retrofits system-wide in the event of generation shortages or high costs.

The general DSM would be evaluated against generation, transmission, and system-wide distribution costs, while the targeted DSM would use generation, transmission, system-wide lower-level distribution costs, and area-specific higher-level distribution costs.

FUNDING IRP ACTIVITIES

Most of the distribution utility's IRP activities could be funded by a combination of

- assessing direct charges to participating customers for electricity (from distributed generation) and ancillary service (power quality, backup power);

- increasing general distribution charges to recover of costs of expanding distribution capacity, as under current ratemaking;

- directing the avoided distribution costs (including losses) from DSM, distribution efficiency, and distributed generation to pay for those activities;

- recovering some of the DSM-program costs from participating customers with their savings in generation and transmission costs (including losses).

- These funding sources should cover most costs of distribution efficiency and distributed generation, with the possible exception of the portion of costs justified by environmental benefits.[21]

Due to the persistence of market barriers, it is unlikely that participants will be willing or able to pay fully for the benefits they receive from DSM; indeed, in many market-transformation efforts, the ultimate beneficiaries are not directly involved in the program and may not be identifiable. Some form of additional funding is likely to be required for DSM, low-income programs, and possibly some distribution efficiency and distributed generation.[22]

Continued provision of these services requires a funding source and mechanism, and an entity responsible for implementing the programs. There are many options for such funding, as the following suggests:

- *Funding source:* distribution utility, generators, marketers, all utilities in state, all-fuels energy fee, pollution fees, tax revenues.

- *Funding mechanism:* as needed and cost-effective; fixed cents per kWh; fixed dollars per year; annual acquisition goal (e.g., percentage of kWh sold).

- *Implementing entity:* distribution utility, state energy office, special state agency, independent contractor.

Depending on the nature of the restructured electricity market, almost any combination of funder, mechanism, and implementor may be feasible.[23] Additional options and variations are possible in each of the categories. For example, one implementation entity may serve the entire state, one contractor may be used to deliver service for each distributor's service territory, or service territories can be split into regions. One contractor may serve all classes, or separate implementors (with different types of expertise) can serve residential, multi-family, small commercial, large commercial, and industrial process customers. The implementor can provide services directly; or plan, coordinate, inspect, and evaluate the work of a range of contractors who perform those services. Each efficiency delivery structure also requires some form of oversight.

More than one funding structure may be appropriate simultaneously. Many restructuring proposals have suggested that a fixed cents-per-kWh *stranded-benefits charge* be assessed on all sales (either directly on marketers or by requiring all sales to flow through the distributors), to fund renewable energy, DSM, low-income programs, discounts to existing electric-heating customers, and perhaps other activities.[24] This charge may be collected state-wide, and would be particularly suitable for activities that are naturally uniform over time and across regions: funding low-income discounts and efficiency, establishing a regional renewables infrastructure, transforming markets, demonstrating stricter building standards, training trade allies, and changing retailers' practices in stocking equipment.[25]

Stranded-benefits charges can be expended through statewide agencies or contractors, or divided between statewide, regional, and utility-specific efforts. The distributor has special advantages in reaching and working with customers (usage and payment records, a low-cost billing mechanism, regular monthly communications with every customer), and should be involved in supporting many of these activities, even if it is not responsible for implementation.

The stranded-benefits charge is not well suited to funding distributed generation or targeted DSM, the opportunity for which may vary widely over time and between distributors. The distribution company should have a separate mechanism for funding these activities. Distributed utility planning should not be constrained by a predetermined benefits charge, nor should it divert needed funds from the activities funded by that charge.

CONCLUSION

To paraphrase Mark Twain: news of IRP's death has been greatly exaggerated. Contrary to claims by some observers, the economic rationale for integrated planning and the opportunities for utility DSM investments will continue in a restructured industry. Distribution utilities are likely to retain responsibility for minimizing their customers costs through integrated resource planning and acquisition of efficiency resources less expensive than supply alternatives. Opportunities for utility investment in customer efficiency improvements are also likely to continue, as market barriers to customer investment and barriers to market entry by retail-service companies will persist.

Market restructuring will likely require new methods for evaluating resource benefits, strategies for DSM-program implementation, and approaches to funding IRP and DSM efforts. These new approaches tailor the IRP process for a restructured market, providing the means for distribution utilities to maximize economic benefits from integrated planning in a competitive environment.

NOTES

1. The IRP process has been implemented to different degrees in various jurisdictions. This paper describes a composite IRP process, typical of that intended in the jurisdictions that have actively engaged in IRP.

2. This paper does not explore the validity of the argument that PBR can substitute for regulatory requirements to pursue IRP. Nevertheless, we note that PBR generally provides incentives to utilities to reduce their own spending, not total costs to ratepayers and society. Moreover, PBR may lead utilities to focus on strategies that reduce short-term costs without consideration of cost implications in the long term.

3. With regard to the implementation of PBR, the California Public Utilities Commission (1995, section 3.E) asserted, ''Our goal is to have an improved regulatory process that offers flexibility and encourages utilities to focus on their performance, reduce operational cost, increase service quality, and improve productivity.''

4. For example, the Vermont Competition Working Group (1995, unnumbered 3rd page and note a) adopted the principle that a restructured industry should ''seek to maximize customer value at the least cost to society'' including in this concept ''both customer value and costs that would result from efficient markets and those other costs that are external to market transactions.''

5. The distribution utility could invest in DSM savings that cost more than the avoided distribution-service costs, but less than the total avoided generation, transmission, distribution, and customer-side costs, as long as the utility could recover from the customer a large enough share of the DSM cost to reduce the utility's investment to below the amount justified by distribution benefits.

6. During the transition to competition, regulators are likely to require distribution utilities to minimize the total energy-service costs for their core customers that continue to take bundled service.

7. Restructuring need not entail an economic loss if an appropriate state or regional agency can provide the full range of DSM services justified by total energy-service benefits.

8. For a review of the performance of shared-savings programs, see Nadel, Pye, and Jordan (1994). For a detailed discussion of the limitations of market-based efficiency services, see Chernick, Plunkett and Wallach (1990).

9. These market barriers notwithstanding, market competition may encourage power marketers to invest in some efficiency. As bulk power supply becomes more of a homogeneous commodity, marketers may need to distinguish their product with innovative services on the customer's side of meter, including energy efficiency, power quality, and on-site generation. However, this use of efficiency for marketing purposes is likely to concentrate primarily on low-cost, easily understood measures, which face the weakest market barriers to begin with.

10. The environmental problem is more likely to get worse than to improve. Utilities may have been more willing to spend money on reducing or mitigating environmental effects, especially if cost recovery is largely pre-approved, than would lightly regulated generating companies operating in a highly competitive market, without assured cost recovery.

11. The distribution utility will not be in direct competition with the generation companies, but it may compete with other distributors for the location of large customers, based on distribution rates, regional power costs, other regional costs (transportation, labor, land, taxes), and assistance in cost reduction. If the generation function is separated from the retail utility, the local utility will not be able to attract load with a low price for bulk power, since the same power supply will be available over a wide regional area.

12. Demand-side management will create lost revenues for distribution utilities to the extent that distribution investments are recovered through demand or energy charges and that DSM reduces customer billing demand.

13. Alternatively, an appropriate state or regional agency could be responsible for this function. We do not discuss this function further.

14. This is one of our frequent criticisms of avoided costs estimated by utilities, especially those with excess baseload capacity. See Chernick, Plunkett, and Wallach (1993, 36).

15. This has been true for recent estimates of avoided capacity costs by Central Vermont Public Service (Bentley 1994, exh. BWB-4) and Green Mountain Power (1994), and more consistently in Resource Insight's corrections to those utilities' avoided-cost estimates (Chernick 1994, 1995). On the gas side, Boston Gas (1996) today bases its avoided capacity costs on its estimates of regional capacity costs.

16. Generation-related transmission costs should probably be included in the estimate of generation costs, although the ultimate source of the data will still probably be the transmission company. The estimation of avoided transmission costs is discussed in Chernick, Plunkett, and Wallach (1993, 61–67).

17. The estimation of avoided distribution costs is discussed in Chernick, Plunkett, and Wallach (1993, 68–83) and in NARUC (1992, 136–144).

18. Transmission lines appear in this list because the distribution companies are likely to continue to be responsible for the transmission-voltage lines that serve only their distribution substations, while regional transmission operators will run the grid that interconnects generators with load centers. While the regional grid will usually operate at higher voltages than the local-delivery transmission lines, this is not always true. No national standard exists for separating transmission and distribution voltages: 32 kV is a transmission voltage for some utilities, primary distribution for others, and sub-transmission for still others.

19. The sizing of distribution equipment is driven by apparent power (measured in kVA) rather than real power (measured in kW). Additions can be deferred by reducing kW loads, increasing power factor (the ratio of kW to kVA), or both.

20. The relevant resource costs are net of avoided generation, transmission, lower-level distribution costs, and environmental benefits, as well as any other ancillary benefits (improved power quality, back-up power, and the value of thermal energy from fuel cells, improved energy services from DSM). Many of the ancillary

benefits can be charged directly to the customers who receive them.

21. The costs of distribution capacity expansion will be covered by cost-of-service ratemaking, or whatever performance-based ratemaking scheme evolves for the distribution utilities.

22. Economic development may be a net source or sink of funds.

23. Some of details of the efficiency delivery structure are dependent on the new industry structure. Each industry structure has a different set of actors who can be required to collect a fee, meet acquisition goals, acquire allowances or credits, etc.

24. Many jurisdictions have been reluctant to require customers who were enticed into adopting electric heat in the early 1970s, when electricity was cheap, to pay the full cost of service in the 1980s and 1990s.

25. Some provision should be made to allow programs to follow fluctuating needs, due to weather (greater need for fuel assistance), the economy (increasing low-income requirements, or increasing the demand for new-construction DSM), or technology.

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