HELPING DISTRIBUTED RESOURCES HAPPEN:

A Blueprint for Regulators, Advocates, and Distribution Companies

FINAL REPORT

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EXECUTIVE SUMMARY

This paper provides a framework and a set of overall recommendations for encouraging the use of Distributed Resources (DR). DR refers to the use of electricity generation, storage, distribution, load management, and/or geographically-targeted energy efficiency to eliminate or, more often, delay capital investments in electric transmission and distribution (T&D) systems. The focus of this paper is on the use of DR to avoid or defer *local* T&D system investments, as compared to regional and inter-regional transmission investments. Local T&D constitutes the majority of total T&D utility capital costs.

DRs have many attractions. They can replace or, more often, delay investments by a distribution utility (independent Disco or distribution-end of an integrated utility) in T&D, and also help avoid central plant generation costs. In many situations, DRs can reduce the level of customer investment in power quality and reliability. By being near loads, they minimize line losses.

DRs help moderate utility financial risks in many ways:

1. They can be developed in small modules to match loads.

2. Through their small scale, they minimize the impact of equipment design flaws.

3. For many DRs, by buying additional modules one can provide backup capability with modest investment.

4. If they are added in small increments, DRs minimize the risk of incorrectly guessing loads.

5. Under many local conditions, the most suitable DR is less expensive than the combination of additional central generation and T&D.

6. Many DRs are more environmentally benign than central generation and T&D, and are (at least potentially) less risky, faster, and less expensive to license.

7. Local DRs can also cumulatively reduce the need for regional and interregional transmission.

8. An additional societal benefit is that DR investment can keep power system and T&D system investments in the local community. Benefits are itemized in more detail in *Section 2*.

A rough estimate of the portion of the national T&D investment that might be diverted to DRs is from about $800 million to $2.5 billion/year. This excludes the associated central plant generation investment, which would be replaced with a combination of local generation, load management, and energy efficiency.

Over the next ten years, a significant amount of local generation is likely to be common, regardless of the level of utility support and integration into T&D planning. This is due to:

1. Decreasing costs and increasing reliability for microturbines, cogeneration, fuel cells, wind, etc.,

2. The ability for some technologies to address customer power quality and reliability issues, and

3. Increasing customer and service provider sophistication.

If distribution utilities integrate DR into their T&D planning, it can significantly reduce utility and societal costs, and create significant environmental benefits. If they do not, a significant threat to the long-term stability of distribution utility rates and finances can occur because of stranded investments in T&D improvements.

Effective integration of DR into T&D planning can occur only if steps are taken among both distribution utilities and power providers to:

1. Enhance the coming small-scale power boom,

2. Integrate it with energy-efficiency opportunities, and

3. Then coordinate it with the T&D planning process.

While a few utilities have enthusiastically embraced and are exploring DR, at most utilities it is developing slowly, if at all. This is due to numerous factors which will continue to retard DR growth in the absence of strong regulatory support. These barriers to DR include distractions, knowledge gaps, perverse incentives, and institutional issues. Most utilities will not overcome these factors without appropriate encouragement from regulators and advocates. This encouragement must go beyond exhortations to *"Do DR"* and address the reasons why *"Doing DR Right"* is difficult.

The following section summarizes some of the more important barriers to large-scale DR implementation, and provides elements of a regulatory and utility management strategy for addressing these barriers.

SUMMARY OF KEY BARRIERS AND ACTIONS

1. ***Traditional data sets and tools for T&D planning are not designed to fully assess the costs and benefits of DR (see Section 3.B for details).***

Response: Encourage distribution utilities to, and reward those who:

a. Use well-designed screening methods – which consider a wide range of possible benefits – to identify good candidate sites for DR study.

b. Compare existing T&D methods to the most significant opportunities and benefits from DR at particular sites.

c. Work with forecasting, load analysis, and T&D/DR planning tools that address multiple resource options and multiple benefits, at least for selected sites with good prospects for cost savings from DR.

d. Collect and use hourly substation load data, and data on customer end-use for DR study areas.

e. Gather intelligence on customer plans and long-term trends for local generation.

f. Work with customers to "firm up" local generation plans to reduce planning uncertainty, where this lowers T&D cost and investment risk.

This encouragement should be matched by realistic expectations that full integration of DR into utility management will take years of persistent effort, and will require attention to the details of market development and institution-building. While distribution utilities should be encouraged to address important issues and develop defensible and flexible planning frameworks, regulators and advocates should recognize that the best DR planning approaches, tools, and resources vary by utility because of different T&D systems, growth, concentration of loads, and other circumstances. It is important to encourage distribution utilities to plan to address a consistent menu of issues and opportunities while adapting to local circumstance.

2. ***Many distribution utilities lack the internal knowledge of energy efficiency and customer end-use to incorporate it into T&D planning. Even fewer have a full understanding of customer power reliability needs and the implications for local generation and T&D systems. Distribution utilities will be slow to "trust" this knowledge until it is institutionally internalized (see Section 3.B).***

   Response: Expect utilities with the most customer sophistication, and those where that sophistication is close in the organization to T&D planning, to take the lead. Reward utilities who develop the requisite sophistication and knowledge. Discourage utilities from dismantling their customer service organizations once restructuring puts them out of the generation market.

3. ***Distribution utility standards and assessment methods for power reliability are neither consistent enough or, for some utilities, detailed and customer-oriented enough to adequately assess the relative merits of T&D versus DR development (see Section 4.C).***

   Response: Encourage the T&D engineering community to develop guidelines to support rules for interconnection, backup power, power quality, etc., which are rationally consistent and pertinent to local conditions. Local generation should be treated as a T&D system component, with appropriately stringent requirements, but no more stringent (given equipment characteristics) than for T&D equipment. Also, encourage the use of data on the value of T&D system reliability to local customers in B/C analyses.

4. ***For many utilities, backup power, buyback, and other DR-related tariffs are not set to maximize the benefits of DR to the utility system or society (see sections 4.D.2 and 5.A.2). Many existing rate policies actively discourage Distributed Generation.***

   Response: Promote tariffs which encourage economical DR. Encourage utilities who have historically discouraged independent generation to recognize the advantages of encouraging DR as a tool to avoid risky capital investments.

5. ***Regardless of utility efforts, an increasing volume of small-scale generation and efficiency projects will be initiated by: 1) generators seeking to minimize their power costs through sophisticated power sales and service agreements, and 2) large businesses seeking to address reliability and power quality issues. If not carefully coordinated with grid planning, this could move load from generation peak times to peak times for the local T&D system (often different from generation peak times). Without coordination, distribution utilities may also build T&D capability to serve loads which disappear from the grid a few years later due to these efforts by generators (see section 4.D.2).***

Response: Encourage distribution utilities to develop communication with power brokers and local potential generators to coordinate development. In many cases, utility investments to "firm up" local generation or DSM plans will be financially preferable to new T&D investments that serve uncertain loads. Regulators may need to require that power marketers participate in these coordination arrangements.

6. ***Because DR benefits depend on local circumstances (e.g., load patterns, facility needs, future independent customer actions), and because DR investment decisions are made in much smaller increments than for power plants, traditional approaches to regulatory oversight for DRs will not be effective (see Section*****s 4.D.2 and 5.A.2).**

   Response: Regulators and advocates must understand the nature of T&D planning and DR characteristics sufficiently to make good policy. This paper offers some initial guidance. Regulators must also set policy in such a way as to encourage distribution utilities to create *appropriate experimentation* with DRs and then *effective systems* for DR planning and implementation, without trying to review or adjudicate the many individual T&D improvement plans which a utility produces in a year.

   Regulators also must recognize that there is no single template that will work to standardize DR planning or analysis. Best analytic tools, technical solutions, power resources, and most important benefits differ from site to site. Regulators can define the critical overall questions that must be addressed and issues that must be resolved. They can also create an environment where distribution utilities benefit from developing effective methods within these guidelines, and from sharing their learning with others. However, enforcing a consistent approach and method in detail, or trying to micro-regulate every individual investment decision, would be counterproductive.

7. ***In states with competitive retail power markets, competition for generation is likely to be effective only if generators are separated from monopoly distribution customers (to prevent abuse of monopoly advantages in power sales competition). Yet, to integrate local generation into T&D system development, independent distribution utilities (Discos) will need to coordinate with and, in many cases, influence DR development. The need for close utility integration will be most important in the next few years, when utilities should be encouraged to gain experience with DR use for T&D project deferral (see Appendix C).***

   Response: In the short term, regulators should allow Disco ownership of limited, clearly T&D-targeted generation, on the condition that the power be sold to wholesalers or power exchanges, not on the retail market. Discos should be encouraged to co-invest in customer projects to reduce uncertainty about T&D demand. (See item 5, above, regarding coordination with power developers.)

In the long run, Discos should be encouraged to offer price signals for development of DRs by others. However, it will take significant time to develop a group of contractors which is diverse, competitive and reliable enough so that utilities can count on a bid-based DR contract as much as their own construction of a substation.

8. ***Industry restructuring is diverting attention to stranded cost and other generation issues (see Section 5.B.2).***

   Response: *In the short term, encourage experimentation* with DR through focused regulatory directives (addressing needs for experimentation and policy analysis), through cost recovery, and through incentives. Develop broader policies (rates, rewards, terms for coordination of generation and T&D development), once more DR experience is gained and the confusion from restructuring has diminished**.**

9. ***Competitive utility cost-cutting is discouraging the type of long-term investment in research, experimentation, human capital, and organizational development needed for utilities to make DR work (see sections 4.D.1 and 5.B.2).***

   Response: Inform distribution utilities of the enormous risk of stranded costs if they *fail to plan* for local generation. Provide the regulatory rewards and prodding to encourage appropriate action. In developing new rate and regulatory structures, consider both the need to reward cost-reduction through DR in the long run, and the investments in experimentation in the short-run. To assure that these investments are well-directed, regulators will need to set up a clear, and at least moderately-detailed, agenda for effective DR planning.

10. ***Most current cost-of-service regulatory mechanisms tend to discourage activities like DR, which can reduce T&D investment. Many regulatory analysts prefer performance-based ratemaking (PBR) systems. These have the right long-term philosophy (utilities should make money by reducing costs), but discourage the short-term investments in becoming DR-capable. Furthermore, nobody knows the appropriate cap levels for PBR mechanisms because the potential for cost reduction from improved T&D management is both huge and not yet well-estimated (see Section 5.A.4).***

    Response: Regulators using both cost-of-service and PBR regulatory systems will need specific provisions to encourage and reward DR development and implementation in lieu of T&D investments. Regulatory approaches which do not explicitly address the need for DR will likely not be effective in encouraging DR. Since Disco costs will be dominated by T&D investments, and DR may significantly influence investment levels, an approach which does not work well for DR is unlikely to be optimal in terms of overall customer benefits.

11. ***Local land use and Federal and state air pollution regulations often do not consider the tradeoffs between one facility and another. As a consequence, new local generation plants may face resistance, even if they have positive net impacts on local and national environmental concerns.***

Response: Land use and clean air regulators need to develop systems for considering new generation sources in the context of their impact on existing emissions sources. Land use planners need similar tools for understanding the benefits and concerns regarding local generation.

12. Many DRs are most economical if they are part of business facilities or residences, (e.g., cogeneration, efficiency, load management, solar, fuel cells); yet, only the most sophisticated customers are capable of managing a generation plant. Many lack the interest or contractual sophistication, or do not wish the hassles and risks of having a third-party contractor manage an on-site power plant (see Section 5.B.1).

Response: DR should be first developed with the most motivated and sophisticated customers. Utilities may have an easier time than most private firms in attaining customer trust; this is another reason why it makes sense for Discos to initially own some DRs. For the more reticent customers, focus on more familiar measures (efficiency, load control) or off-site power.

ACTION PLAN

Section 6 provides an action plan based to overcome these barriers nationally through a series of specific projects and initiatives. The primary elements of this work plan are:

a. Business, Financial, and Public Benefits Analysis of Distributed Resources

b. Distributed Resources Pilot Projects

c. Develop Rational and Fair Standards For Distributed Generation (DG)

d. Develop Policies for Generator/Disco Coordination of Load Management

e. Develop Fully Integrated DR Capability at Select Utilities

f. Encourage Movement Toward DR Capability Among Other Utilities

g. Develop Coordination Mechanisms for National Development of DR

1. INTRODUCTION

This paper provides a framework and set of overall recommendations for encouraging the use of Distributed Resources (DR). The intended audience is regulators, advocates, and champions of DR within utilities.

1.A. WHAT ARE DISTRIBUTED RESOURCES?

DR refers to the combined or individual use of electricity generation, storage, distribution, load management, and/or efficiency in specific locations to eliminate or (more often) delay transmission and distribution (T&D) system capital investments (i.e., facility expansion or construction). The focus of this paper is avoiding investments in T&D by an independent distribution company (Disco) or the distribution end of an integrated distribution, transmission, and generation utility. Generally speaking, "distribution utilities" or "utilities" in this paper refers to either an independent or integrated distribution company. Disco, in this paper, generally refers to an independent distribution company working in a state where distribution has been functionally separated from regional transmission and generation of power.

The all-inclusive DR concept should not be confused with Distributed Generation (DG), which encompasses only generation alternatives. Nor should it be confused with use of small-scale power and efficiency resources for generation only. DR, as discussed in this paper, involves purposefully distributing resources *placed within the power grid* in such a way as to minimize power, transmission, and distribution costs in combination.

1.B. WHY ARE DISTRIBUTED RESOURCES IMPORTANT TO REGULATORS AND ADVOCATES?

Advocates and regulators should facilitate utility development of effective DR programs, and utilities will find it profitable to pursue them for several reasons:

- DR investment will often be critical to minimizing future distribution rates.

- DR investment will facilitate both improved electrical end-use efficiency and development of clean distributed-generation technologies.

- Effective DR programs will optimize societal, utility, and customer benefits from the coming dramatic increase in customer-driven development of distributed generation. Without proper attention to electric system planning and integration, customer-driven generation will result in the possibility of significant stranded T&D investment, creating higher distribution costs and significant utility financial risks.

To provide some sense of how important DR might be, we have estimated a rough range of potential for DR investment. National annual investment in transmission and distribution facilities has been running from $12 to $15 billion dollars per year over much of the past decade. Effective DR programs will shift some portion of this annual investment stream away from traditional investments, like transformers and wire conductors, to DRs. A rough estimate of the portion of this national investment that might be diverted to DRs is from about $800 million to $2.5 billion/year.[1] To provide a regional pont of reference, from about $80 million to $150 million/year might be diverted to DRs in New York and New England alone. These estimates exclude the generation investment which DR will defer from central plants and supplant with local generation, load management or conservation. Thus, the figures cited above are quite conservative.

In many situations, utility DR investments will not need to cover the full cost of DRs, because there is significant value to customers in the DR, in terms of provided power or reduced power needs, and improved power quality and reliability of power.

In spite of significant work on DR by utilities and groups such as the Electric Power Research Institute (EPRI) over the last several years, the road map for increased use of DR is unclear for a number of reasons:

- Traditional utility planning systems for meeting generation, transmission, and distribution needs do not provide ***an adequate analytic framework for considering DR.***

- While forward-looking regulators in several states have taken steps to encourage the use of DR, ***the benefits from and requirements for the broader use of DR are not well understood by many policymakers.*** They are therefore not well-addressed in existing frameworks for utility governance (rate making, facility approval, profit regulation, etc.).

- ***The US system for governance and administration of electric utilities is in a state of flux***, adding complexity and ambiguity to the situation, and distracting utilities, regulators, and advocates from the immense opportunities available from DR.

- ***DR value is local and circumstantial, and time lines for deferring T&D projects are often very short. DR alternatives must be very reliable, or must incorporate backup.***

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[1] These figures are based, in part, on Dave Andrus's estimate that about 60% of total annual national transmission and distribution system capital investment is in distribution facilities and that about 50% of distribution system investments are load related. (The remainder of such investments are typically to replace worn out or damaged equipment, or to improve reliability). We further assume that from 25% to 75% of the load-related investments are potentially displayable by DR. The extent to which DR is applicable to load related investments has not yet been determined, and some reviewers of the first draft of this report thought this figure might be high.

These considerations increase the level of sophistication needed to effectively utilize DR and limit the effectiveness of "simple market solutions" such as a system-wide proxy price for T&D deferral.

- ***The "best" methods for planning and using DR are still being developed***. Some of the foremost planning exercises and tools have not been critiqued or discussed beyond the technical community of T&D planners.

- With recent advances in metering and automated control technology, and the increasing importance of power quality issues, more DR options are now practical, and many of the benefits to grid operation can be utilized, measured, and understood. ***However, recognition of these new opportunities and options is only slowly filtering through the utility and regulatory community.***

- While most utilities have expertise in T&D construction, ***only a few utilities have enough internal experience and competence with energy efficiency or load management for T&D planners to trust those resources to take the place of transformers and wires***. Even fewer utilities have the expertise in customer-side power reliability issues to recognize the value of DRs to customers, and the potential for their cooperative development.

This paper examines these barriers in more detail and proposes a series of activities to address them.

1.C. THE PURPOSES AND ORGANIZATION OF THIS PAPER

This paper presents a primer and initial strategy for regulatory and advocate efforts to encourage DR. There are many technical papers, technical conferences, projects, and experts on DR. This paper attempts to synthesize and explain the key policy hurdles to widespread use of DR, and the possible means for overcoming those hurdles. To this end, the remainder of this paper:

- Further describes DRs within the context of distribution system design *(Section 2)*;

- Summarizes the planning and implementation processes for T&D development, describes how DR fits into them, and what must be done for utilities to become fully DR-capable *(Section 3)*;

- Examines the forces leading toward increased local power production and DR utilization *(Section 4)*;

- Reviews opportunities to enhance the trend toward DR and the constraints which may make it difficult *(Section 5)*; and

- Provides a national agenda for advocate, regulatory, and utility action *(Section 6)*.

Three appendices provide further details on: safety and reliability issues related to local generation *(Appendix A)*; flexibility in local transmission planning *(Appendix B)*; and the need for Disco control over some generation during the exploratory phase of DR in order to assure progress *(Appendix C)*.

The focus of this paper is on managing DR to address the need for local distribution system expansion, including adding or enhancing substations, feeders, and local power transmission (i.e., transmission within a 100 mile area, lines under 600 KV). DR can also help defer investments in larger regional and inter-regional transmission systems. We chose not to focus on these broader needs because the regulatory and business environment for interregional transmission is being reinvented as we write, and the outcome is far from certain. Changes in the regulatory and business environment will drive the planning framework for regional and inter-regional transmission in ways which cannot yet be predicted. If transmission is regulated largely at the federal level, it will present a set of issues which are more complicated and essentially different than those addressed here. Furthermore, most of the capital investment in the power grid is in the distribution of power. By covering local T&D, we are covering most of the economic opportunities.

Thus, when this paper refers to transmission, it generally means local transmission.

2. WHAT ARE DISTRIBUTED RESOURCES AND WHAT ARE THEIR BENEFITS?

As discussed above, DR can include generation, both renewable and nonrenewable, energy storage, energy efficiency, customer load management, or any combination of the above. It can be initiated and owned by the customer, a utility, or a third party. The key characteristic is that it is developed to meet a specific need in the T&D system, at a specific place, congruent with the timing of peak loads, much as would be met by a new or reconductored power line, a new substation, or a new transformer. For example, at a location where electric loads reach their peak at 6 p.m. on weekdays, the DR must also provide near-maximum output or load reduction at that time.

The attractions of DR to society and the utility are many. They vary depending on the particular need and environment where the T&D improvement is required, and on the specific technology used. An exhaustive list is documented in a forthcoming report from the Rocky Mountain Institute.[2] Several of the more important benefits are discussed further in this paper. A quick summary list is provided below.

- DR both reduces T&D capacity needs and central generation requirements. For the most costly T&D investments, DR provides lower capital and life-cycle cost-per-unit of combined generation and T&D. Costs for many DR technologies (generation, load control, and efficiency) will decrease as they are produced in higher quantities. This will lead to an increasing number of economical applications. Additionally, the economics improve as the many ancillary benefits discussed below, and in the RMI paper, are considered.

- As a consequence of proximity to load, DR reduces T&D system energy losses by reducing the length of line, and the number of transformers, which power must pass through.

- DRs can improve system and customer power reliability due to:

    1. Proximity of generation to loads (less line length equals fewer opportunities for problems);

    2. The inherent superior reliability of some (but not all) DR over traditional generation;

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[2] Lovins, Amory B., and Lehmann, André, *Small is Profitable - The Hidden Benefits of Making Electrical Resources the Right Size,* Rocky Mountain Institute, Publication pending in 1999.

3. Opportunities, for some local generation technologies, to provide low-cost redundancy with modular small-scale construction of power resources (e.g., add one 200 kW fuel cell to a bank of four fuel cells as a back-up); and

4. Opportunities to use certain types of local generation to actually cancel out power quality problems (e.g., specialized inverters).

- Usually, DR resources result in less conflict over siting and other environmental issues, as compared to new central generation, power lines, and substations. One exception is land use; many DRs are sited close to urbanized areas, where there is often close regulation of activities, appearances, noise, and emissions. Typically, land use planning looks at an individual facility, and not at the tradeoffs with alternatives (e.g., build several local plants, but avoid a transmission line or larger local plant). Without consideration of these tradeoffs, there may be more resistance to local generation than would be created by a look at the tradeoffs. This may complicate local permitting for DG. Land-use regulators need to develop new knowledge, criteria, and standards to make appropriate and quick decisions regarding new, local generation Local generation is also greatly complicated by clean air regulations, which, in a similar way, often ignore the benefits of reduced generation from a dirtier and less efficient old source. EPA is currently grappling with ways to consider tradeoffs in permitting for cogeneration plants and other local generation.

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- Most conservation measures, small scale renewables, microturbines and fuel cells provide power through smaller, modular projects. If the modules are mass produced, DR can have shorter lead times than larger generation. This significantly reduces planning and financial risk in many ways. For example, there is less chance of stranded costs if loads do not show up, a better ability to manage cost overruns, an ability to switch if a technology or supplier is not delivering, etc.

- The small, modular projects also allow the utility to more closely match load growth when staging projects, resulting in less unused capacity. Large generation and T&D projects require adding capacity in large "chunks" which result in initial underutilization.

- DRs result in reduced environmental harm as a consequence of the superior emissions characteristics of many DRs (energy efficiency, fuel cells, low-emission generation), lower power requirements (due to line loss savings), and less land use development for transmission and distribution (especially with efficiency, load management, and on-site customer generation).

- DRs offer opportunities to customize characteristics of power sources (purity, reliability) to meet customer needs through the nature of the DR plant.

- Successful DR for local distribution purposes may also reduce the amount of regional and inter-regional transmission needed.

- DR investments are made in the local community, while cental plant generation may be remote. Thus, DR may provide more local economic benefits.

DR can be utilized at a single feeder, at a single substation, or for larger areas served by local transmission. At smaller scales, time horizons for planning usually are shorter. One difficult issue, especially for smaller projects, is the ability to predict T&D enhancement needs in sufficient time to consider and develop DR alternatives. Advanced planning is easier for the larger areas.

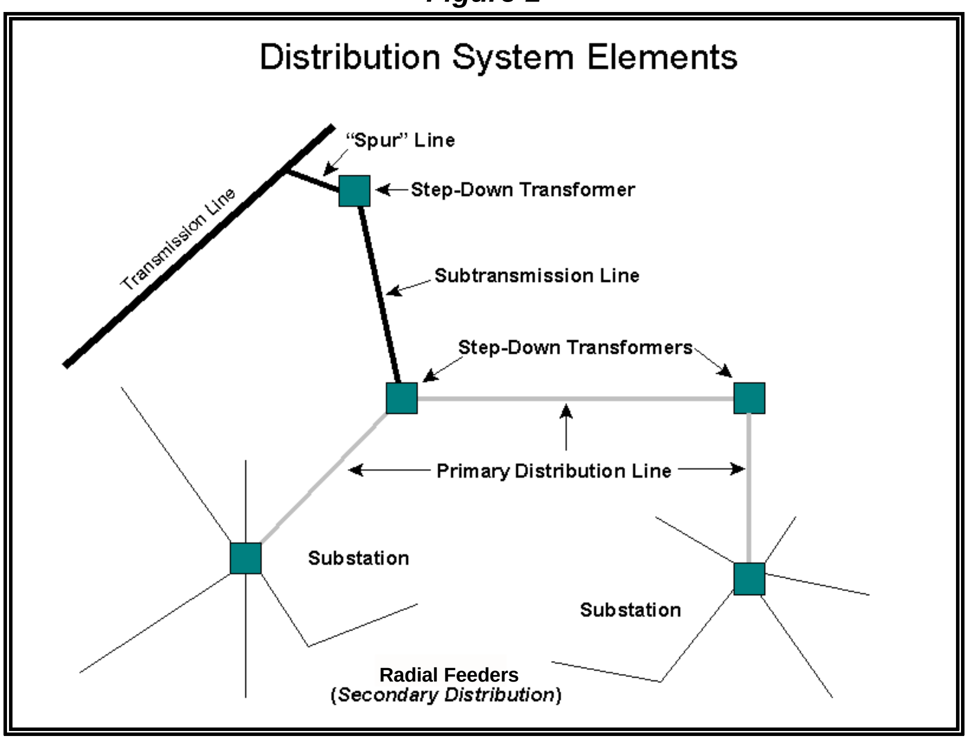
Unfortunately, many DR pilot projects have been at the smaller-end of the size spectrum. Nevertheless, some large, high-cost local transmission projects may provide some of the crucial early opportunities for DR (e.g., expanding ski areas).

3. DISTRIBUTION SYSTEM PLANNING TODAY

3.A. STRUCTURE OF DISTRIBUTION SYSTEMS

The purpose of distribution systems is to distribute power from the transmission system (which operates at high voltages to minimize losses) to customers. Typically, distribution systems will include step-down transformers at the transmission line to reduce voltage to levels suited for delivery along a primary distribution line to a distribution substation. The distribution substation contains another transformer (along with power regulation and other equipment) that further reduces voltage to levels appropriate for delivery along radial "feeders" (secondary distribution lines) that run from each substation to customer facilities. Another transformer is located in, at, or near customer facilities (homes, commercial buildings, etc.) to reduce voltage to levels appropriate for power distribution within those facilities. These transformers are often located on power line poles. *Figure 1* illustrates some typical distribution system configurations.

Figure 1



An important characteristic of all distribution system components (transformers and wire conductors) is that they have peak power loading limits. Typically, if power loads within a specific portion of a distribution system have grown to levels approaching relevant equipment limits, such equipment needs to be replaced with equipment having higher load-carrying capacity. Thus peak loads – not volume of energy flow – are the basic force driving distribution system capital equipment needs and, thus, distribution system costs.

Another important characteristic of distribution systems is that customers' load characteristics typically vary greatly within a distribution system. Consequently, each distribution feeder may have a different "load shape". Each substation's load shape is the sum of load shapes of the individual feeders connected to the substation. Opportunity to invest in DRs as an alternative to traditional distribution system equipment are defined by the load characteristics driving the need for new investment. Examples of load shapes that may typically be found in certain parts of distribution systems are shown in *Figures 2* through *5*.

Figures 2 and *3* show a portion of a distribution system with a relatively flat load that is approaching equipment load limits. Any DR option to address this problem would need to have a high "capacity factor" as, for example, might be the case with customer energy-efficiency or distributed generation to provide assured power to economically-sensitive customer loads.

Figures 4 and *5* show a portion of a distribution system with relatively "spiky" loads. A good DR option to address this situation would be dispatchable (i.e., on-command from the power system) customer load reduction.

Secondary or lower-order distribution lines which deliver power directly to customers are called *feeders.*. As shown in *Figure 1*, for systems which do not have DGs on the feeders, these lines are laid out in a radial manner (i.e., with lines radiating from the source transmission line to feed local areas). The only exceptions to radial feeder configuration are network systems found in many metropolitan areas. Network systems are designed as a grid, but even so, these systems actually deliver power in a radial fashion. While power can be transferred laterally in these networks, radial operation is essential to safety; linemen must know that if the line is disconnected from the source, they can safely work on it.

Local power generation raises significant worker-safety issues, because lines which are isolated from the transmission system may still be "live" with local power. There are also grid-control issues when central power is off-line. While the details need to be worked out, it appears that, with further attention to grid control and operational protocols, these issues can be resolved. *Appendix A* provides further detail regarding these concerns and potential solutions.

The nominal voltage levels of primary feeders are between 2400 V and 34,500 V. Under normal operating conditions, the real power flow (watts) at any point on the primary feeder is always in one direction – from the substation outward, or downstream.

Figure 2

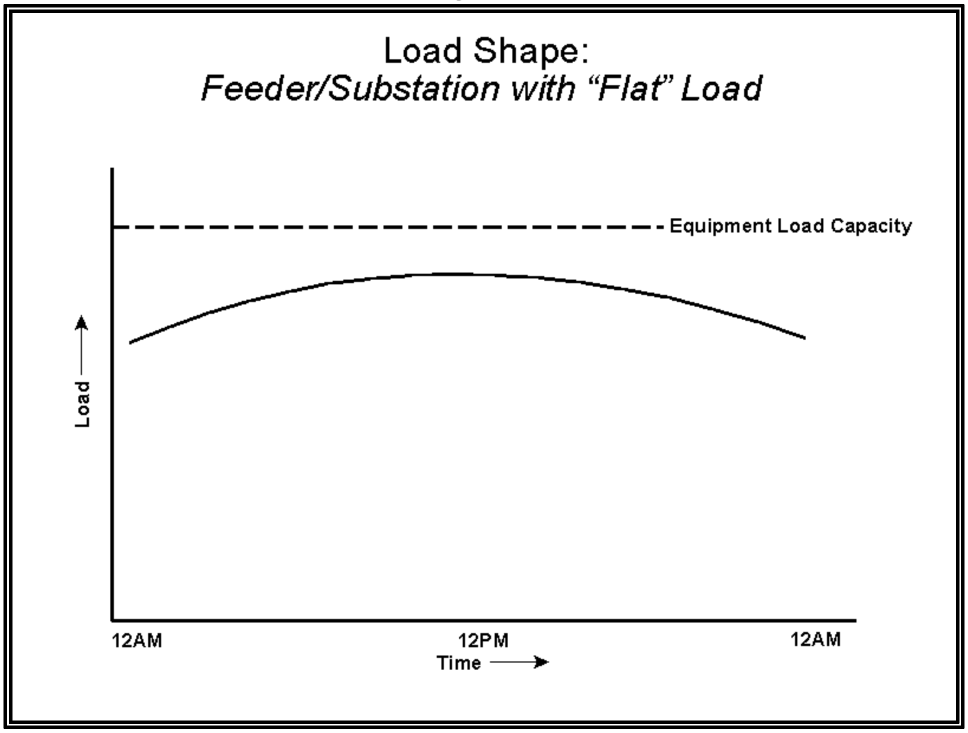


Figure 3

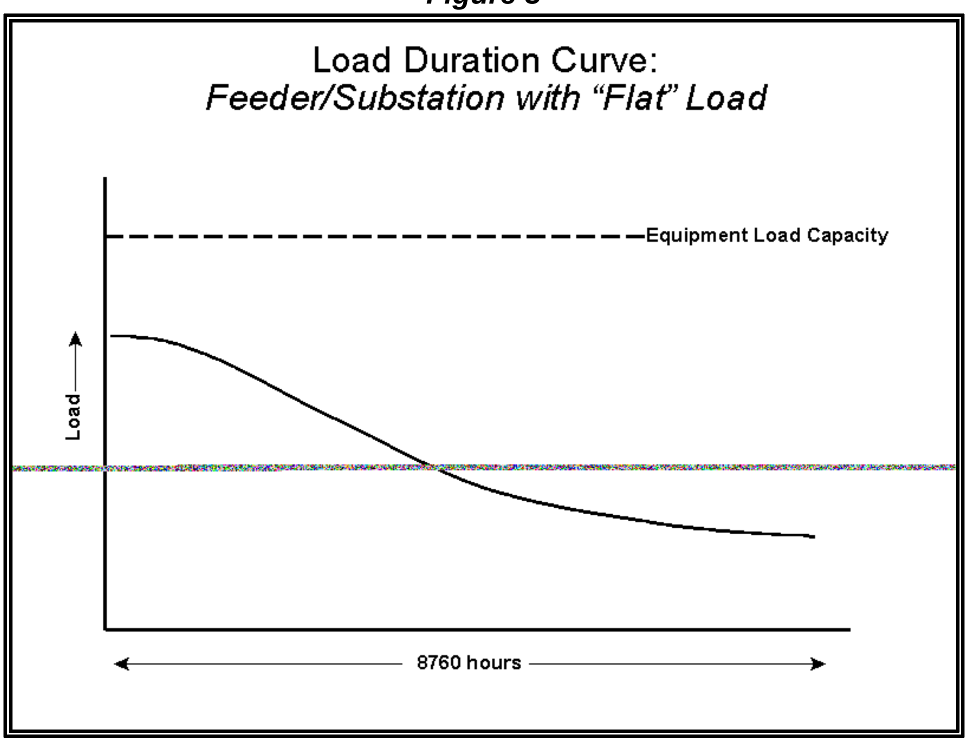


Figure 4

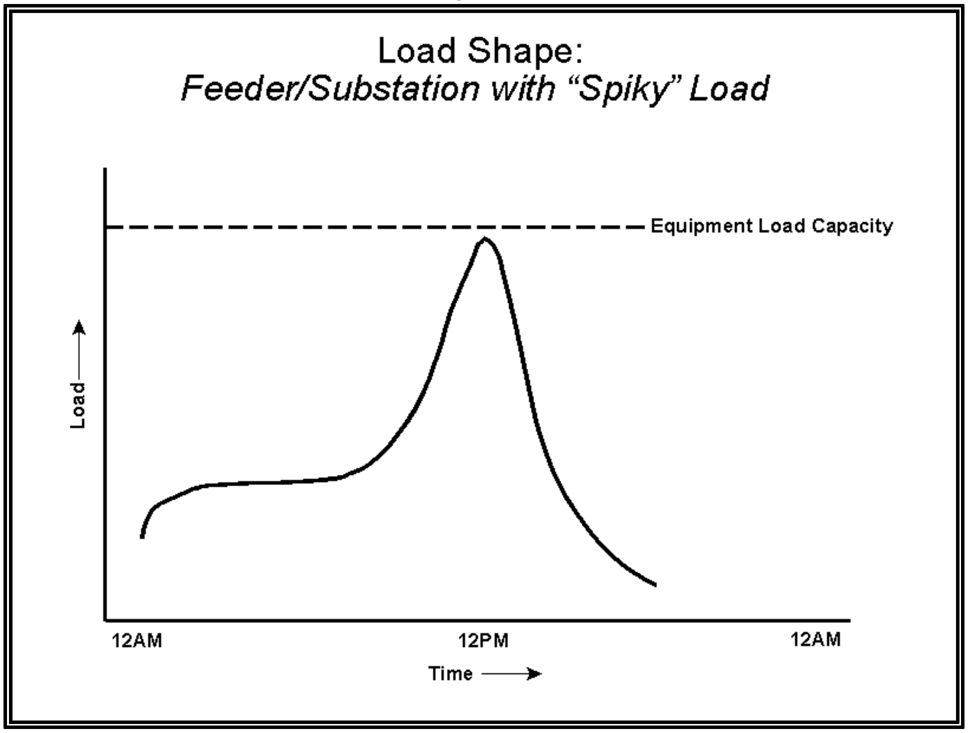
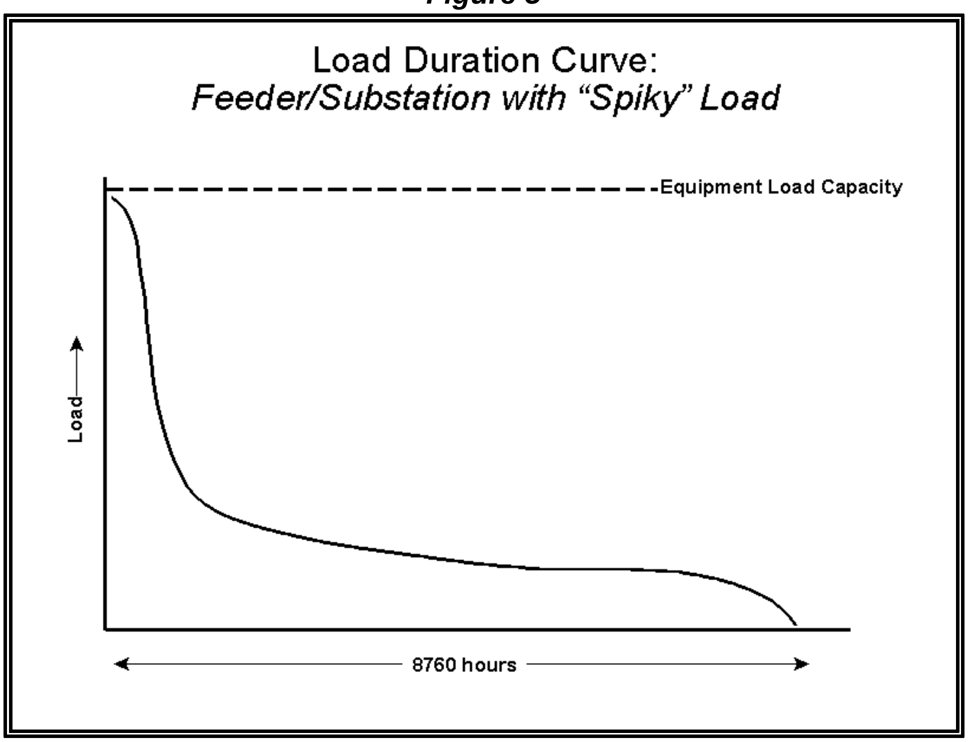


Figure 5



When maintenance operations are being performed, or a system is being reconfigured, two feeders may be temporarily tied together at points remote from the substation. This is done to avoid momentary outages to customers whenever switching is performed. In these situations, there can be power flow between feeders, but the parallel operation of feeders generally will last for only minutes, after which the system is returned to the radial configuration.

The proximity of different radial spokes to other spokes, and the ease of interconnection, is important for reliability purposes. Proximity is also a key influence on the cost of upgrading service. Where there are many spokes at close proximity, and some are under-loaded, it is relatively easy to address a capacity shortage or reliability problem by shifting load between substations. If necessary, a power line is run a short distance. Where radials are geographically isolated, or where all radials are approaching capacity at the same time, T&D enhancements tend to be more expensive per kW, and also to have a longer lead time. This environment tends to be more hospitable to DR.

3.B. INVESTMENT PLANNING FOR DISTRIBUTION SYSTEM IMPROVEMENTS

This section briefly explains how improvements to T&D systems are planned and implemented, with special attention to DR issues. This topic is important because inadequacies in planning and data collection systems for DRs are key barriers to widespread use of DRs in T&D planning. Policymakers can address these bottlenecks by encouraging utilities to make the requisite investments, carefully assessing the adequacy of efforts underway, and rewarding appropriate research investments. *Section 5.A* discusses strategies for targeting innovations to the areas where success is most likely.

3.B.1. Planning Methods

In today's transitional, partially-deregulated utility business environment, utilities may no longer be required by regulatory agencies to provide a least-cost plan, but may be driven by competition to provide the best customer service for the most competitive price. Since T&D costs are borne directly by the utility, and the quality of delivery directly impacts customer perceptions of service, many utilities are continuing to plan carefully for T&D improvements, and some are considering DR alternatives.

In distribution system planning for DR, planners compare the costs of alternatives for serving increases in load on portions of the distribution system. These alternatives can include any combination of the following:

- Purchasing power to meet generation needs, and, at the same time, finding ways to use the existing T&D system better to meet loads.

- Purchasing power to meet generation needs and, at the same time, upgrading the distribution system (and perhaps the transmission system) to meet delivery needs.

- Installing other DR options, or motivating their installation by others,[3] to address generation, distribution, and perhaps transmission needs.

Standards of Need

The core of distribution-system planning is the set of power-reliability standards used by utilities to identify "need" for system improvements. These standards can consist of:

- Rules of thumb developed by the utility (e.g., based on manufacturers' recommendations about capacity limits of certain critical distribution equipment),

- Frequency and duration of outages on different parts of the distribution system, or

- Comparison of avoided outage benefits (reduced costs) to improvement costs, using benefit/cost analysis.

    - Most commonly, this comparison is based on utility costs of outages, assessed through a probability analysis related to equipment loadings, age, etc.

    - A small, but growing, number of utilities are beginning to assess value to customers of reliability (especially for large customers) and incorporate it in expansion studies. There may be consideration of whether increased reliability from customers can enhance revenues, either through customer retention and growth or through premium reliability charges.

This needs analysis is used to make utility investment decisions. It is also used to build public support for utility proposals for system improvements in the face of concerns about rate, land use, aesthetic, and sometimes perceived health impacts.

Step One: Assure that T&D System is Fully Utilized

The first step in DR planning is always to assure that opportunities to minimize need for capacity through low-cost manipulation of the distribution and transmission system are exhausted. Strategies can include both load manipulation and reassessment of equipment capacity. *Appendix B* discusses

3 Methods for motivating DR installation can include pricing options such as real-time and/or area-specific pricing, or offers to contribute to or pay for local power resources.

one type of optimization tool which is increasingly gaining acceptance: situation-specific assessment of equipment capacity.

It is important that DR proponents recognize that these actions can be legitimate and sometimes have financial and environmental benefits to DR. System management innovations should be considered to be complements to DR, as long as the advantages and costs of each are fully considered.

Step Two: Compare Options for T&D Enhancement and DR

Once the need for more available distribution capacity is confirmed, an analytic approach to compare, and perhaps combine, DR to T&D investments is needed. A common DR planning strategy is to use the conventionally-derived minimum-cost distribution expansion plan as a base case against which to evaluate DR strategies. This is a useful approach for situations where the T&D planning framework provides adequate time to consider DR alternatives, or when portable T&D equipment or other measures can be used to stretch timelines. However, traditional T&D planning approaches put off T&D investments for as long as possible, and then assume that the utility must choose one option from a short menu of standard solutions. It may be valuable in some cases to take a geographically broader and longer-term approach to forecasting T&D needs than has been traditional, to identify opportunities for DR with sufficient lead time to act.

There is not a well-established protocol and set of tools for comparing T&D and DR investments. Traditional approaches do not mathematically consider the financial and risk mitigation value of deferring T&D investment through other activities. Some more recent T&D planning models[4] are more sophisticated in dealing with DRs, and in considering financial risk, load matching over time, performance risk, etc. However, these models have had limited real-world field testing, and are not in common use. Most utilities have not developed all the data needed to feed these models and decision processes.

Even the new models do not thoroughly deal with many environmental, customer acceptance, system stability, and power quality differences. Full integration with generation planning is outside the scope of these models. Furthermore, issues of customer economic benefits of DRs (e.g., greater reliability and power quality), and the opportunity to share costs with customers who reap these benefits, are largely outside the scope of the models.

Integration of Generation with T&D Planning Tools

There is considerable, albeit scattered experience, with comparing energy-efficiency options to T&D options. However, consideration of local generation as an alternative to T&D construction is a

[4] E.g., a recent EPRI model called the *Area Investment Strategy Model.*

relatively new development. Most utilities have always planned separately for T&D and generation. Procedures for integrating generation planning and distribution planning at most utilities are largely ad hoc.

For post-restructuring utilities, where generation is in a separate legal entity and Discos may be barred from generating power, even the legal and regulatory issues for coordinating generation with T&D are not well-defined. *Appendix C* discusses some of the reasons why DR development may require that Discos have some involvement in selected generation projects, and how this may be accomplished while allowing unfettered competition for retail power sales.

Why Have These Issues Received Limited Attention to Date?

First, while T&D expenses are as large as generation expenses for many utilities, they usually come in smaller increments. This has reduced their visibility to regulators, and the attention they received from utility managers. Second, there are many different benefits of DR to consider. It is difficult to examine them all and methods are not well-established for quickly identifying the most important for a particular site and set of options.

Additionally, many utilities have traditionally oversized distribution,[5] in response to crude and optimistic load forecasts, economies of scale, and the rewards of cost-of-service regulation (bigger costs mean more profits). Big facilities also minimize the number of times the utility needs to apply for difficult land use and environmental approvals.

All, or most, of these conditions are likely to change as a result of deregulation, or as a consequence of the very different political, financial, and environmental characteristics of DRs. However, much of the basic developmental and pilot work needed to plan and utilize DRs is in its infancy and many of the leading tools have not undergone extensive pubic scrutiny.

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[5] Despite past T&D oversizing there will continue to be need for new T&D capacity. This is true for several reasons:

- While many utility systems are on the average oversized, the oversizing hasn't always occurred where load growth subsequently is occurring.
- Many utilities need to make significant investments in replacement of obsolete or aging equipment, or are considering T&D investments to reduce power losses.
- Without the impetus of DR, many utilities may not enhance their planning and metering sufficiently to "fine-tune" their methods of assessing T&D needs. In an era of cost-cutting there is inherent resistance to putting more money into research and development tasks.

3.B.2. Data for Distribution System Planning

Distribution System Area Cost Data

It is important to configure distribution system expansion (and operatoins and maintenance) cost data in a form that is comparable to costs of DR alternatives. This allows the two alternatives to be evaluated side by side. The more straightforward types of distribution system cost savings which can be credited to DR alternatives include:

- Life extension of old equipment due to lower loads
- Deferral of investments in new equipment
- Maintenance deferral
- Reduced real and reactive power losses

As noted in the introduction, these are complemented by an array of financial, reliability and social considerations which have rarely been considered in the past.

These factors can be summarized as area- and time-specific marginal costs. Area specificity is important because only certain feeders or other T&D equipment may be in need of upgrade, while others may not. Time specificity is important because the local area peak may or may not coincide with the system generation peak. An option that is valuable for reducing system peak may not be as valuable for reducing the T&D area peak, and vice versa.

Local Load Profiles

Feeder load shape data serve the following purposes both for T&D expansion and DR analysis:

- Assign marginal capacity costs to specific hours..
- Help identify the DR strategies which are most appropriate to address the specific load shape.
- Compute the percent change in end-use loads due to DR implementation.
- Estimate effects of changes (from DR or other reasons) on reliability.
- Forecast load growth and load shape change.

For many utilities, feeder load profiles may already be available via a utility's routine data collection, while other utilities may not have invested in hourly metering for many feeders and substations. Some utilities do not even know what the peak day is on feeders, because their metering only shows what the peak loads are.

Where feeder load profiles are unavailable, a number of alternative means, ranging from borrowing data from other utilities, to statistical analysis, to metering of actual loads, can be used to develop such data. However, secondary data are useful in considering DRs only if the end-use characteristics of data source and subject feeders are similar. This is because the load-shape characteristics of the local feeder and of end-users help indicate whether specific types of DRs (which are often tied to end-use, solar cycles, etc.) match the time of system peak.

Many utilities do not have the sophistication in understanding their end-use loads to consider these matches carefully. This capability is likely to be greatest for utilities which have sophisticated internal DSM market analysis capability, and where DSM and T&D functions are organizationally close.[6]

In the current cost-competitive environment, many utilities are hesitant to invest in "research" efforts to meter substations, because they view the costs as being real and current, while the DR benefits are both speculative (based on the utility's lack of experience) and prospective. This reticence to invest in metering is a major barrier to DR growth.

Feeder load duration curves (showing the number of hours in the year with different levels of loads) are sometimes used to assess load patterns. Load duration curves do not say *when* loads are at certain levels, only how often. This approach is inadequate for analyzing the benefit of many efficiency, cogneration, load management and solar DR measures. These measures often have specific load shapes, following solar cycles, matching use patterns for equipment, etc. It is impossible to say from a load duration curve whether the DR is "on" during the high-load hours.

Load duration curves are also falling out of favor among more sophisticated analysts of distribution equipment capacity because carrying capacity of T&D equipment has been found to vary, depending on the number of consecutive high-load hours. This helps DR advocates justify more sophisticated data analysis methods.

Reliability Data

Most utilities collect baseline distribution system performance or reliability information, but the type and amount of information collected for these figures does not always adequately represent performance. Typical distribution reliability indices include the following:

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[6] See *Section 4.A* for further discussion

- Customer Average Interruption Duration
- Customer Average Interruption Frequency
- Average System Availability
- System Average Interruption Frequency

For many utilities, data collection on system reliability is sporadic. To fill the gaps, information is often imputed from the design of the lines delivering the energy and the loads being served.

Comparison of the reliability of DR options with T&D expansion is likely to be a difficult issue because existing information on T&D equipment reliability is spotty, yardsticks are inconsistent across the industry, and data on the reliability of DR options is limited and not well-known by T&D planners. In our experience, a minority of utilities currently have sufficient, systematic data collection systems regarding reliability to fully consider customer values in making T&D/DR tradeoffs.

Regulators and advocates may need to promote more methodical and consistent (between alternatives) data collection for T&D and DR options, not only to assure the rational use of DR, but to improve the cost-effectiveness of T&D improvement planning as a whole.

Local Load Forecasts

Typical local area load forecasts for distribution planning use a combination of trend analysis, local economic forecasts, and discrete data about customer plans. The forecast is generally considered to be a fixed and determined aspect of the planning process. In the best cases, two or three alternate forecasts are used to bound the uncertainty about loads. Compared to system-wide forecasts for generation planning, local area forecasts tend to suffer from limited customer characteristics data, over-reliance on trending, and the limited investment that can be justified for forecasting loads at a lesser scale. For some utilities, there is a further problem in that the forecasting areas do not coincide well with the areas served by specific T&D equipment, and the growth rates differ between the two.

Even with better data, customer decisions are inherently unpredictable. Change can be sudden at the small geographic scale of substations and primary feeders. For most utilities, the predictability of loads varies greatly from one substation to the next. For example, one substation may primarily serve residential customers, with a diverse economic base and a slow, steady growth rate. Loads are relatively predictable. Another substation may serve one large industrial plant, and also serve businesses and residences which are dependent on that plant. A decision to add a third shift, or cut production in half, will impact all those loads profoundly and rapidly.

The type of load growth influences the type of DR which is most applicable. In the case of slow, steady load growth, a utility might favor a resource which can be added gradually in small increments, with the rate of implementation fine-tuned to meet load growth (e.g., efficiency or a load management program for many customers; the modular addition of photovoltaics, small fuel cells or small generators).

In the case of highly uncertain large load changes, the utility might favor resources which could be installed quickly, or are portable.(e.g., fuel cells or generation on a truck, or a large volume of portable solar arrays). For this type of environment, it is most valuable to have an established DR support industry ready to provide high volumes of equipment on short notice. The availability of such a rapid response capability has great value to the utility in maintaining reliability and avoiding exorbitant improvements.

Forecasting of Customer Generation

T&D forecasts have traditionally assumed that the utility will serve all load growth, with the exception of some large industrial customers that cogenerate (e.g., many pulp and paper and petrochemical facilities). Generally, these few, large sources of local generation were dealt with as discrete phenomena, and simly subtracted from load forecasts. For reasons discussed in the next chapter, local generation is expected to grow significantly, and much of it may consist of smaller-scale plants. In some cases, utilities will be faced with a choice of augmenting and encouraging the acceleration of local customer-initiated generation or making a T&D investment which might not be needed in ten years, once local generation reaches a certain level. The balance will depend on the level of potential and likely local generation. Unfortunately, most utilities who are closely following independent generation development have done so primarily to avoid losses of power sales and the attendant revenues. They have not devoted resources to forecasting independent generation over several year, nor on thinking about its impacts on T&D planning.

It will be important for T&D planners to know where local generation is likely to come into play in the next several years, and also to identify where local generation is close-to-economical for customers. In these situations, prudent utilities may choose to co-invest with the customer in DR options, both to reduce uncertainty about needs for T&D enhancements and to do so with customers picking up a significant share of the cost. For most T&D improvements, understanding possible customer projects over the next 5 years or so would be most useful, in that it fits the time frame for T&D planning.. In some cases, where major enhancements to the grid are considered, a longer time-frame is relevant. For the short-term, information may be available from customer requests for study of interconnection. Additional data could come from discussions with large customers. The most difficult task will be to identify the potential for small-scale DR at multiple sites, which may happen quickly and in a dispersed fashion, and is dependent on both technical and market developments whose time-frame is difficult to predict.

Comparing Cost and Value of Purchased Centrally Generated Power to the Cost and Value of Local Power Produced or Made Available by DRs

Both distributed generation resources and energy efficiency increase the amount of power available for sale. This is a key element of the value of these resources to the sponsor, be it the utility, the customer, or a third party. Accordingly, this value must be integrated into the T&D planning analysis. When a Disco invests directly in DRs, that value is a direct benefit to a utility. When a Disco tries to encourage others (customers or developers) to own and operate DRs, the value is to the owner. However, that value influences the amount that the Disco might need to invest to make the DR worthwhile to the developer.

For a customer/owner facing relatively constant rates, as is often the case today, the prevailing rate may be an adequate proxy for this value. However, as power markets better reflect the value of load shape, power quality, and dispatchability, these variables will become important to the sponsor in assessing value of DRs, and therefore important to the Disco for reasons stated above. For very clean power, and users who need it, proximity may have its own value. While utilities have well-established mechanisms for estimating the value of power, power quality is not typically considered, and proximity value is not considered at all.

Even for traditional concerns like the value of power by time-of-day and year, changes to power markets are rendering forecasts less reliable. Pricing is likely to be volatile for many years as the new market for power “gets its legs”, and as waves of improved generation technology arrive. Values of power to customers will depend on the contingencies included in their power purchase contracts.

We expect generation companies (Gencos) to pursue advances in power price forecasting as a key to their own survival in a competitive world. However, to the extent that Discos are separated from Gencos, this sophistication may not be available to T&D planning. Even where it is available, it will take a significant effort to interpret the information in ways which are usable by T&D planning processes and models. Part of this task will be to reconfigure the processes and models so as to assess the financial implications of price uncertainty, as well as the added dimensions of value discussed above.

3.B.3. Cautions About DR Analysis[7]

Based on the discussion above, this section summarizes some key areas where mistakes and misperceptions are commonly made about DR analysis for T&D expansion. Many of these are areas where DR planning methods differ from those employed in system-wide integrated resource

[7] This section borrows liberally from: ABB Power T&D Company, Automated Distribution Division, *Introduction to Integrated Resource T&D Planning*, 1994, Raleigh, NC.

planning, in T&D planning which does not employ DR, or in energy savings-oriented DSM measure analysis (not focused on peak savings).

1. System-average estimates of T&D marginal costs are not adequate for DR analysis. Marginal T&D costs vary locally, based on the time of peak, equipment in place, ease of improvement by location and proximity to other lines, local development costs, etc.

2. Lifetimes of T&D improvements versus DR options differ. For example, a transformer may last longer than a lighting fixture. The analysis must adjust for this.

3. It is important to distinguish between the costs of *deferring* T&D investments and the full capital costs of those investments. It is also important to consider unusual time-related characteristics of some DRs such as high salvage value or portability.

4. Peak times (which drive T&D costs and savings) differ between a piece of customer equipment, that customer as a whole, the local T&D component, and the utility system as a whole. Data must be developed to understand the coincidence (or lack thereof) between these peak times. Generally, it is more important to know the local T&D and system-wide generation peaks from specific equipment than to know the equipment's peak loads. Customer peaks are important for analyzing customer benefits, where peak charges apply.

5. With the exception of isolated radials, service areas for many T&D facilities are fluid and subject to change by transferring loads between facilities. Where the cost of transferring loads is low, the opportunity to do this is significant, and the lead times are short, DR becomes pertinent only when there is an eventual need for enhancements to the broad area served by the network. Where the cost of transferring loads is higher, lead times are longer, and transferring is less feasible, studying DR in relation to proposed individual substations and lines makes more sense.

6. Finally, it is important to study the impact of DRs on the load shape, not just the existing peak. For example, a load management measure may push peak load into a "shoulder" period. This might create a new peak time, and sometimes may create an even higher peak load at that time.

4. AGENTS OF CHANGE

This section discusses the forces which are moving utilities toward DR utilization, and their prospects.

4.A. UTILITY EXPERIENCE WITH EFFICIENCY AND LOAD MANAGEMENT

Customer energy-efficiency improvements and load management can reduce customers loads and can thus serve as DRs. Utility DR experience to date generally suggests that distribution planners are far more likely to consider efficiency and load management as DRs if their company has had prior experience with them. This is both due to their comfort level with the technologies and (as discussed in the prior chapter) the availability of customer-characteristics information to assess the potential local load savings.

Since the late 1980s, many utilities developed large-scale efficiency and load management programs and the associated internal expertise in markets, programs, and evaluation. This collective body of knowledge, which essentially did not exist until the early 1990s, is essential to widespread consideration of efficiency and load management as DRs. Utilities with strong efficiency and load management programs, but a historical reliance on resource bidding, standard offers, or other pay-for-performance programs, may have measurement capability but very little in-house customer data or market analysis capability. This may create a significant problem for DR analysis.

Utilities who have experimented with a variety of efficiency and load management programs have made their own assessments of the relative reliability of different approaches. It is interesting that the distribution planners in one utility which has experimented with DR are much more comfortable with energy efficiency programs than with interruptible rates.[8] This is because the persistence of efficiency measures is relatively predictable, while interruptible rates allow customers a year-by-year decision regarding load reductions.

In a similar fashion, utility experience with various forms of local generation tends to create more understand of and comfort with these options.

However, because understanding the multiple benefits of DR requires changes to analysis tools, organizational structure, and decision-making process within utilities, only a handful of utilities appear to have converted their operations to use a significant fraction of the potential from DR. While the DR pioneer utilities know that DR works, and have benefitted from it financially, they are

[8] Reported by Jeremy Newberger of New England Electric in comments on the draft of this paper.

still figuring out how to maximize the benefits, mass produce analyses, and profitably export knowledge.

4.B. THE DG TECHNOLOGY BOOM

A convergence of factors is leading to an increased availability of local generation at lower prices, and with higher reliability. Currently:

- Widespread experience with cogeneration since the advent of PURPA has led to increased sophistication of equipment control for operation and grid integration.
- A series of innovations in turbine design in the aerospace industry have increased reliability and decreased cost. These are just beginning to enter the generator industry.
- In the last year, significant advances, both in the manufacture and in the development of marketing alliances, indicate that a large-scale market for small-scale gas turbines (microturbines) in the 30 to 200 kW range may be quickly evolving.[9]
- EPRI is proposing a pilot project for 3-5 MW mobile gas turbines which are potentially cost-competitive with larger units. Their portability makes them particularly attractive for DG applications, since they can be moved in quickly to address short-term needs, and moved out if loads do not appear as projected.[10]
- Westinghouse and some other manufacturers are working on combined cycle fuel cell/ turbines which could significantly improve the heat rate (i.e., efficiency of power production) for small generators.
- As detailed in the next subsection, customer power reliability and quality issues have led sensitive customers to explore on-site generation.
- Photovoltaic costs are dropping to the point where its use to avoid high-cost line extensions is clearly viable for some off-grid applications (e.g., remote billboard, area lights). Further decreases are expected in costs for both photovoltaics and fuel cells.

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9 See Gerald Cler & Nicholas Lenssen, *Distributed Generation: Markets and Technologies in Transition*, Esource, January 1998, for a comprehensive review of cutting-edge small generation technology. Also see: Victor de Biasi, "Low Cost and High Efficiency Make 30 to 80 kW Microturbines Attractive", *Gas Turbine World*, January-February, 1998

10 "EPRI is working on a utility program to try out distributed generation set", *Gas Turbine World*, July-August, 1996.

4.C. EMERGING REQUIREMENTS FOR ASSURED AND PREMIUM POWER

The most profound trend in customer power requirements in the next decade is likely to involve power quality. The increased concern with power quality has resulted both from increased need and from increased opportunity.

4.C.1 Power Quality Problems

Among electric customers of every description, electronic controls and computerized equipment are proliferating. They are both a significant source of harmonic and other power-signal distortion and are very sensitive to distortion produced by other equipment. For many industries, tiny interruptions or fluctuations in power cause very expensive plant shutdowns, or ruin batches of material. The silicon chip-growing industry, for example, has struggled with power-quality needs because brief down-time results in spoiled, very expensive product.[11] Textile, pulp and paper, and many other industries suffer from both sensitive controls, and high-power equipment which tends to distort power supplies. Other users such as airport traffic controllers and bank data processing centers use large amounts of electronics and place a high premium on reliability.

4.C.2. Power Quality Solutions

To date, the primary response has been a rapid expansion in the market for local uninterruptible power supplies, usually consisting of parasitic (power using) power-smoothing flywheels or filters, battery storage, and controls.

Utilities have responded to increased concerns about power quality, both by upgrading control of their distribution systems and by offering power-quality management services to customers. These responses have occurred in an environment of much opportunity and some confusion. Utilities can improve grid reliability, but have found that many power quality problems originate within their customers' facilities and are difficult to address on the grid without huge investments. Since most customers are not super-sensitive to power quality and do not wish to see rate increases to provide enhanced power quality, utilities often view such problems as the responsibility of the customers who are generating and experiencing the problems. Power quality management services, usually on a for-fee basis, have provided a way for utilities to get customers to help share the costs of sorting out customer-side power quality problems.[12]

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11 Cleavelin, C. Rinn, Ph.D., Texas Instruments, "Power Quality Perspectives in the Semiconductor Industry", In *Signature- A Power Quality Newsletter*, Volume 7, #4, Fall 1997, Electric Power Research Institute, Palo Alto, Ca.

12 A summary of utility power-quality programs is provided in Nicholas Lesson, *The Evolving Market for Power Quality and Power Integrity Services*, Esource Strategic Memo SM-97-1, January 1997.

4.C.3. Role of Distributed Resources in Power Quality Issues

Some solutions to power quality problems can also help address local power distribution constraints. Specifically, both fuel cells and photovoltaic cells provide exceptionally clean and reliable sources of power. Additionally, some generators have inverters which are capable, under the appropriate control, of balancing out and canceling problems with power factor or harmonic distortion on the grid.

One of the first economic markets for fuel cells is proving to be customers who need a high-quality uninterruptible power supply for loads of at least 200 kW. While fuel cells are not economic today, based on the cost/kWh of electricity generated, in some circumstances, the overall cost for power cleaning is comparable to a UPS, making the power provided virtually free.

Markets for clean, reliable power are likely to drive up volume demand for fuel cells and solar, which could help push production cost down further.

4.C.4. Implications for Distributed Resources

Over a period of five-to-twenty years, a significant (but difficult to estimate) portion of load on the distribution system from commercial and industrial customers who are sensitive to power quality disruptions is likely to disappear off the grid as these customers discover the power-quality attributes of fuel cells, solar, and other distributed-generation resources. While customers will initially want grid backup, they will progressively become comfortable with the idea of using modular technologies to provide redundancy of DRs, and will ask for utility backup only when it is cheaper than DR redundancy, or when it provides assurance against different types of events. In effectively deregulated power markets, this trend may accelerate because. as regulated utilities get out of the generation business, their opposition to new sources of generation will disappear.

In addition to removing loads from the electric grid, these sources are likely to sell some power back to the grid.

While this will not make most grid electric loads disappear, reductions in peak loads will eventually be significant, and will be geographically "lumpy," focusing on power distribution nodes with the most eligible types of loads.

The societal and utility benefits of this trend depend on how well-coordinated it is with utility investment in T&D. Consideration of utility peak power needs could lead to significant changes in the design and operation of independent power facilities, with sufficient financial benefits to reward both the utility and the generator. Advance knowledge of independent generation plans could allow utilities to defer or eliminate some T&D improvements. However, this entails a whole new set of utility intelligence-gathering activities, business relationship-building, and contract evolution. Because small-scale generation and power marketer/consumer power products are both evolving quickly, reliable forecasts of independent generation by location will not be possible for some years. As discussed in the last section, it may be in the interests of utilities to act as a co-investor to "firm up" generation plans of independent sources, rather than build T&D facilities to serve uncertain loads.

4.D. COMPETITIVE MARKETS AND THEIR IMPACTS ON DISCO ECONOMICS

4.D.1. Impacts of DR on DISCO Economics

The likely increase in local generation has significant financial implications for Distribution Companies (Discos). If load on T&D systems is reduced, the possibility exists that large prior investments in T&D will no longer be necessary and, in effect, will become "stranded" investments. Most T&D capital costs are recovered by utilities over a 30-year period. Once utility managers are free of the distraction of generation assets (i.e., once utility generation and T&D functions are dis-aggregated by regulators or legislation), they are likely to recognize the enormity of this liability and press for accelerated recovery of costs. This will put considerable pressure on Discos to cut costs in order to minimize rate impacts caused by the accelerated amortization. The rate pressure may press capable utilities toward investment in least-cost solutions, including DR. However, there may also be pressure to minimize research and development costs for DR in favor of well-established planning and equipment approaches. This may keep utilities from learning how to implement DR effectively, or how to assess its potential impact on their T&D investments.

Thus, regulators and advocates will need to work closely with utilities to assure that the short-term financial pressures do not obscure the significant potential benefits of DR in reducing overall debt load. This may require both positive pressure and rewards for DR/T&D research, planning, and practice.

4.D.2. Impacts on Rate Structure

Energy/Demand and Peak Hour Rate Allocation

In states where restructuring effectively separates Discos from power sales, the Discos, once freed of concern for generation assets, will discover that their pre-existing rate structure is largely unrelated to their costs. Currently, most utility rates are dominated by fixed charges and energy charges, but the marginal cost of distribution is almost entirely driven by peak load. For the first two to three years after a state undergoes restructuring, political exhaustion and regulatory inertia are likely to keep regulators and utilities from focusing on this issue. For example, the Massachusetts utility settlement agreements with utilities generally hold to configuration of Disco rates constant for a period of three years.

Over time, however, we expect that Discos will want to rationalize rates by increasing the peak component and decreasing the energy, and perhaps fixed, components. The emphasis will be on increasing costs for the few hours of the year that primarily drive T&D costs (superpeak hours). There are several approaches to this, including a narrowly defined, predetermined peak period, real time pricing,[13] and programs that pay for load interruptions or use of on-site backup generation. While all of these tools are in current use, their emphasis and the maximum rate for superpeak periods are both likely to increase.

Gencos and transmission companies (Transcos) are also likely to more closely identify expensive peak load periods and configure their pricing to discourage loads during their peak periods. Their peak periods may not coincide with those for the Disco. The implications are discussed in *Section 5.A.2*.

Implications of Peak Rate Issues for Customer Actions

Once rates focus sharply on superpeak periods, we expect that at least larger customers will increase their attention to load management. The rate changes will also further encourage on-site generation.

This will work in conjunction with the power-quality issues and technology changes discussed above to further accelerate changes in local peak loads in ways which will be difficult for utilities to predict without extensive reconnaissance or involvement in customer projects. The magnitude of the changes are likely to vary significantly between geographic areas, depending on the type of end-use loads. For example, some large industrial firms may alter operations and find significant superpeak savings, while others may not be able to shut down without costly interruptions in manufacturing activity. Until they are demand-metered, residential customers will largely be unaffected, and residential-dominated feeders are unlikely to change much.

The degree of coincidence between local and system peaks will also vary, and may change with time. Interests and actions of Gencos and Discos may conflict. For example, a generator (Genco) may charge a very high rate for a summer 5-6 p.m. peak, when residential air conditioning loads and commercial/industrial loads coincide. A specific feeder may be dominated by commercial air conditioning and experience a 3-5 p.m. peak. If the Genco has a high peak charge in the 5-6 PM period, a large customer served by that Genco might supercool their chiller in the 3-5 p.m. period to reduce its load during the 5-6 p.m. system peak. This would increase peak loads on the local feeder. Thus, efforts of power brokers and customers to suppress system peak may actually increase local peak. The same type of conflict might occur between Transco and Disco peaks, and even between main power lines and feeders within the Disco.

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[13] Under real time pricing, customers are notified a day or a few hours in advance of hourly electricity prices. This strategy is being tested by numerous utilities with select large customers who have the flexibility to employ on-site generation or reduce loads in response to price.

As a consequence of the divergence of objectives between the system and the locality, there will be a need for coordination in both planning and financial incentives between power marketers, local T&D utilities, and customers. This system could have both regulatory and market aspects. For example:

- Regulations may be needed to assure that generators notify local utilities of efforts to shift load. It may be necessary to require generators and customers to be informed about local system constraints and avoid load shifting to local peak periods (especially if it proves impractical to establish rates based on local periods).[14]

- Gencos and Discos could coordinate efforts to encourage local DRs for areas and hours of mutual concern, in ways which financially benefit both parties.

It will be important that regulators carefully consider what role they should play in coordination and preventing conflicting initiatives. Regulators must devise channels for allowing Genco/Disco coordination on load management without hampering competition for generation.. Given that most utility restructuring initiatives aim for complete separation of competitive generation from monopoly distribution in the market, channels for this coordination will need to be carefully defined and crafted.

Rate Structures to Support and Interact with Local Generation

Local generation rarely matches local loads perfectly. As a consequence, many local generators who are also power users need to sell power to the grid at some times and buy it at others. There is also a need for backup power provisions for local generators who do not wish to lose power when their local plant is off-line, and who do not build redundancy into their local plant. Most investor-owned utilities have developed a series of rates and rules for providing backup power, complementing local generation with grid power, and buying power back.

Unfortunately, many of those rules were developed by integrated utilities who viewed independent local generation as competition, and were therefore not interested in making it easy or attractive. Few utilities considered the positive implications for the local T&D system. Once DRs are recognized by the utility as an asset to the T&D system, these rate policies will need to be revisited. NARUC appears to be focusing on this issue, and it is likely that some states will reform interconnect policy in the next year. It will be important that this be done in a way which allows experience to guide the proper balance between reliability and interconnectability.

[14] A useful first step would be if states forwarded all permitting applications for generation to the host Disco as soon as they were received. However, this would not address load management and other initiatives which are not typically permitted.

A significant potential motivator for utilities is the possibility that overly stringent standards will drive small-scale generators to connect without notifying the utility, leading to a loss of control over interconnect quality. For example, many photovoltaic experts currently believe that there are more photovoltaics connected to the grid that utilties *don't* know about than photovoltaics that they *do* know about. Thus, if utilities set too stringent standards for interconnection, they may lose control of quality on the grid.

5. EMERGING DR OPPORTUNITIES AND CONSTRAINTS

5.A OPPORTUNITIES

5.A.1. DR Planning Opportunities

The sections above indicate that DR analysis often involves:

1. Innovations to analysis processes to consider alternatives;

2. A modified approach to engineering analysis of loads;

3. Additional steps to consider alternatives; and

4. At least ideally, additional analysis to consider reliability, financial risk, power quality, generation characteristics, and other issues which are not typically considered in T&D planning.

It would be cost-prohibitive and wasteful for utilities to completely revise their planning systems to consider these factors in detail for every prospective system improvement. DR analysis involves significant additional planning and data collection investment. These investments only make sense for locations where DR alternatives stand a good chance of being competitive. Furthermore, most utilities will pursue DR widely (among appropriate sites) only when these alternatives are demonstrated in pilot cases.

Thus, it is generally prudent to approach DR incrementally in two respects. First, make a limited number of changes to planning, data collection, and economic analysis at one time. Second, initially target a limited number of sites.

To select the most important economic considerations for a specific site, it is important to identify those conditions which are likely to dominate the economics for that site. RMI's previously cited work[15] presents the most exhaustive list of considerations. Most studies to date have examined only a small fraction of these (although the EPRI model cited previously makes significant advances in this area). It is useful to create a matrix which examines the market and load characteristics of a feeder and candidate technologies as one dimension, and the possible economic criteria as another. This matrix may then be used to identify the economic considerations which are of significant magnitude and which differ between the T&D and DR alternatives. These issues should receive the most focus in the analysis.

[15] Lovins, Amory B., and Lehmann, André, op.cit.

With respect to identifying the most promising sites for study, it is probably important to start with only a few so that adequate attention can be given to innovation and testing of methods for data collection, analysis, and decision-making. The following list provides some characteristics of promising sites:

1. Areas with a relatively-certain, moderate rate of load growth and a need for a high-cost upgrade in the medium term (e.g., the next three to five years).

2. Areas with a moderate, but relatively certain, short-term load growth and significant uncertainty in long-term load growth.

3. Areas where both the distribution system and the central generation system are capacity-constrained and where their peaks coincide.

4. Areas where the proposed distribution system upgrade might face significant and costly siting constraints.

5. Areas where a major industrial customer has a thermal energy requirement that could be met by cogeneration.[16]

6. Areas where certain customers have high outage costs, or where customers have a good opportunity to switch to another supplier of electricity.

7. Areas where addressing T&D constraints through tying lines or transferring loads is costly or expensive due to regional grid saturation, long distances, or physical or urban obstacles to tying lines etc.

One primer suggests that studies should focus on areas of at least five or six substations in order to see how DR impacts the system, considering the ability to switch loads between substations.[17] This may be particularly important in urban areas where radials are close together or well-integrated through cross-radial lines. However, many opportunities occur on a smaller scale and in a faster time frame, or in more isolated settings.

The same primer suggests that areas with relatively low marginal substation re-enforcement costs can still be good DR candidates if high load growth may eventually lead to the splitting off of a new substation (i.e., low short-term costs for re-enforcement, but high costs above a certain threshold).

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[16] This increases the odds that DR is viable, but is pertinent only if earlier criteria demonstrate a potential need for DR.

[17] ABB Power, Ibid.

5.A.2 DISCO Rate and Tariff Design

As discussed above, it will be important to rationalize Disco rates (or, in states with integrated utilities, the distribution portion of rates) to reflect the fact that a few hours of the year dominate Disco costs. Where utility industry restructuring is taking place, attention will focus on this issue only once larger financial issues (such as stranded costs and rules for generation competition) are more or less settled.

It will take some time to restructure Disco rates to reflect the relative cost of energy and peak to a Disco. However, this restructuring is more or less consistent with these tenets of traditional rate regulation:

- Rates should equitably reflect cost.
- Rates should be universal and simple as possible.

The more difficult transition will be from system-wide peak pricing to local peak pricing (in distribution-constrained areas). It is clear that the hours, duration, and cost for peak varies locally. Yet, there is little history or precedent of local electric rates within a single utility. Without accurate local price signals, customers will be encouraged by price to make investments which are not consistent with costs of running the T&D system.

Yet, regulators may have difficulty in moving toward local pricing for reasons both of tradition and equity. This may leave utilities with five rate options for dealing with system constraints:

1. Keep rates the same everywhere, and offer only positive financial inducements to avoid load growth in local geographic areas with impending expansion needs.

2. Keep the average rate per kWh or average kW equal system-wide, but develop more extreme time-of-use or demand rates in areas with system constraints (as part of a total rate package designed to meet the same average in all regions).

3. Treat the entire system as if it were load-constrained, and apply dramatic local real-time peak rates, even in areas where the system will be adequate for many years. Vary only the hours of peak rates locally. This may allow the utility to address local system constraints through rates, but may inconvenience other customers unnecessarily. It also may be difficult to address parts of the system with broader or flatter peaks with this system of rates.

4. Institute high peak penalties in areas where peak growth would lead to the need for new facilities, but only for new customers or new loads.

5. To encourage local generation, offer discounts on the cost of back-up power in areas where peak growth would lead to the need for new facilities. This lesser form of

geographic inconsistency may be more palatable than inconsistent rates for general purpose power sale.

Each of the above options presents technical and political problems. We conclude that rates will most likely imperfectly reflect local costs for a number of years as regulators and utilities hash through this complex set of issues and choices.

5.A.3 Emerging Business Institutions

Utility restructuring and the establishment of competitive power markets are creating new business that will facilitate DR investment. Examples include:

- Power wholesalers who will be able to use dispatchable customer load reduction in the same way that they purchase energy to meet their customer needs at reduced cost. To the extent that such load reduction investments prove profitable, an effective business infrastructure, capable of making such investments efficiently, is likely to emerge.

- “Assured power” vendors who specialize in on-site fuel cell power system development will grow to serve such economically sensitive loads as computer centers and telecommunications facilities. Such companies will typically provide on-site assured power on a "turn key" basis. This overcomes the market barrier of limited customer capability to develop and manage on-site generation.

These and other new forms of businesses will flourish in a competitive market, and will develop capabilities that could support and facilitate many types of DR investment. While both types of business discussed above are beginning to emerge today, they are likely to be commonplace only after several years.

5.A.4. Disco Regulatory Financial Structures

Most U.S. investor-owned utilities are regulated under a cost-of-service system, whereby they are paid reasonable cost for system operation, plus a profit margin. The costs and the margins are agreed on through elaborate, complex, and difficult-to-manage regulatory processes.

After industry restructuring, investor-owned Discos will remain monopolies, and their rates and rate-of-return will be regulated in some fashion. Some states may continue with cost-of-service regulation for Discos. However, other jurisdictions are considering “Performance-Based Rate-making” (PBR) as an alternative. PBR is inspired by the major flaws of cost-of-service regulation:

- The complexity, cost, and difficulty of effective cost-based rate making.

- A philosophical discomfort with the intrusiveness and inflexibility of the rate-making process, and the damper it puts on innovation.

- The inherent bias of the cost-based regulation toward reward for over-forecasting and overbuilding.[18]

PBR generally is implemented as a cap on rates or revenues, either in total or per customer. Under PBR, utilities which minimize costs make more money. One of the most contentious issues for establishment of specific PBR provisions is guessing how much costs "should" go down. Some ratepayer and DR advocates claim that DR provides a potentially huge opportunity to reduce costs, which should be reflected as a declining cap on rates or revenues over time (split the bounty). Utilities, not surprisingly, want to keep the cap as high as possible. In some cases, utilities have been accused of maneuvering to raise rates under the old system to the highest level possible, then set a baseline for PBR.

If DR is to succeed, reward systems will need to assure that utilities who utilize DR are not penalized for doing so. This is true especially during the next several years, when DR will require both financially uncertain experimentation and significant institutional change. It will be important to reward utilities for first experimenting with DR, then create an effective decision framework for DR planning. Still later, there will be a need for systems which permit utilities to bid out and buy DR in lieu of other T&D investments. The nature of this reward system will vary according to the overall utility reward structure.

Cost-of-service regulation essentially rewards more capital investment. This provides several choices for addressing DR:

- Regulators might allow cost recovery, and perhaps a return on investment on research, institutional development, and other costs involved in developing an integrated T&D/DR planning system.

- Regulators might require that a planning system be in place which adequately considers DR before approving inclusion of specific T&D enhancements in the cost base. Alternatively, regulators can offer a lower rate of return if such planning is not in place.

- Regulators might also require that such a planning process be sufficiently public that the overall architecture and specific issues addressed can be reviewed and critiqued by regulators, advocates, and outside experts. Given the traditional insularity of the T&D planning communities in many utilities, and the newness of many of the benefits of DR, this outside scrutiny is likely to be essential for effective DR planning.

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[18] Higher costs are rolled into the base costs for calculating profits based on a percentage.

- Regulators might allow a higher return on investment for DR projects than for T&D investments.

- Regulators might apply a "shared savings" incentive to DR similar to that used in some states for energy-efficiency programs.

Because DR objectives and benefits are very site-specific, regulators are unlikely to be able to review each T&D investment in enough detail to assess whether there was a viable DR alternative. Thus, the emphasis will need to be on creating a *system* where utilities thrive by focusing on DR, and on review by regulators of : 1) the ability of that system to meet key objectives, and 2) its reasonable and competent application for pilot projects, and for the system as a whole.

PBR essentially substitutes a single performance criteria, or a couple of criteria, for the complexities of cost-of-service regulation. The appeal of this idea is clarity and freedom for utilities to act creatively to meet the stated financial objective. However, as a system, PBR does not work well to encourage utilities to meet multiple objectives. While PBR can be modified to include special provisions, the more "special provisions" that are included in PBR, the less it looks like PBR and the more it looks like cost-of-service rate-making without adequate examination of costs.

One could argue that, if PBR is based on minimizing cost-per-customer or kW served, there is a natural incentive to utilize DR wherever economical to the utility. This may be true in the abstract, but this ignores the significant institutional, inertial, and developmental barriers to DR, both within utilities and in the markets for generation, conservation, and other DR services. Rewards may be needed to help utilities learn how to use DR, experiment to discover what the best planning and implementation methods are, and to *establish* the infrastructure needed to carry it out. This will be a multi-year process which will involve significant commitments of personnel and capital.

It is likely that, for the next several years, some rewards system will be needed within PBR systems, for DR to gain much of a foothold in utility planning beyond the few utilities which have already invested heavily and have an internal commitment and capability. Special provisions should probably be similar to those recommended above for rate-of-return mechanisms, even though this dilutes the clarity of PBR.

5.B. CONSTRAINTS

5.B.1. Customer Readiness for Distributed Generation (DG)

Most DR options involve integration of power production or management strategies into businesses and households. Therefore, it is important to understand the degree to which customers are prepared to take a role in energy management, the barriers to their successful undertaking of DR projects, and possible steps to improve their receptivity and capability.

Many large customers are learning to enhance their facility operations to minimize utility costs. Some energy-intensive customers already have on-site generation. As discussed elsewhere in this paper, some customers with a need for exceptional power quality or reliability are beginning to join their ranks. However, the majority of customers, even large customers, still view electricity at best as a commodity, to be bought and forgot, or as an invisible and barely-accounted overhead cost.

A large proportion of building owners and managers chronically under-invest in facility and non-production equipment management, to the point where many building systems barely function at all, are grossly inefficient, and fail prematurely. In fact, many facilities are run by contract maintenance staff who have limited authority to do anything but assure day-to-day adequacy of space conditioning systems, lights, and sanitary facilities. Many systems, especially in government facilities, are undercapitalized.

Utilities and ESCos are beginning to address the resulting opportunities for financial gains through more efficient and effective building energy system management. However, the current generally poor state of building operation and maintenance means that only the most advanced customers are prepared to consider taking on the burden of managing a generating facility. Furthermore, the lack of management focus on building maintenance makes it difficult for third parties to site DR plants within a customer facility. It takes a significant level of interest and sophistication for a customer to contract for third-party services in a new area. Most residential customers have even less capability for managing complex facilities within residences.

To make the conditions for customer participation in DR even more complex, utility restructuring has created the expectation among many customers that utility costs will decrease. This serves as a further disincentive to invest time or money in innovations such as on-site generation. Conversely, if power brokers charge very high rates in the coming years for limited peak hours, this is likely to increase customer interest in facility management.

We conclude that facility energy management capability will continue to be a major barrier to implementation of DR, and that DR programs will need to directly address these barriers to succeed.

As part of their energy efficiency efforts, utilities and other organizations are already testing a number of approaches to strengthening facility energy management, with the objective of saving energy. These include enhanced training and certification, efforts to improve the perceived value of facility managers in the eyes of their overseers, salary guarantees, enhancements to maintenance contracts, commissioning, audit-and-install programs to adjust and repair equipment, and many others. Efforts are just beginning to develop integrated strategies incorporating these elements to sustainably improve building management practices industry-wide. The push for DR should both support these efforts and provide further motivation for them.

5.B.2. Political Instability

The push for distributed generation comes at a very confusing time in the evolution of the utility industry. Restructuring and re-regulation of electric utilities will be a multi-year process in each state. Furthermore, restructuring will occur during different years, and will also have different end-results in different states.

While restructuring will have many and complex effects on the political, regulatory, and economic environment for DR, the primary impact for a period of one to five years after the process begins in each state will be paralytic uncertainty and distraction. Utility and regulatory policymakers will be overwhelmed with other restructuring issues. For this reason, they will most often put off long-term rate design and DR policies until there is time to think and work out these issues through public processes.

Within utilities, DR work has sometimes taken a back seat to the cost-cutting frenzy which was the first reaction in most utilities to mergers and the advent of competition. Long-term research tends to be shunted aside at utilities who are concerned about losing their customer base within the next three years to low-cost providers. Utilities are still sorting out where and how it is profitable to be a “high service” provider versus a “low cost” provider. DR offers opportunities to be both, but it will not impact most customers for many years. This means that many utilities will not devote the intellectual and financial capital required to become proficient at DR without significant outside encouragement.

Realistically, it will be ten years before the smoke clears across the country sufficiently for every state to be in a position to establish sensible, long-term policies on these issues. However:

- Some states are already further along, and will move faster than others. For example, the Massachusetts and Rhode Island commissions will need to begin addressing disaggregated Disco rate issues before the turn-of-the-century.

- Much policy development work needs to be done, and can be done, before long-term policies are established. We can prepare so that when the dust settles, there is an analytic framework and enough detailed knowledge to proceed rationally.

- Significant experimental activity can occur within both the old (diminishing monopoly) and new (chaotic early competition) frameworks without extensive regulatory scrutiny, so long as regulators press utilities to experiment on a small scale and in ways which make overall methods and pilot projects accessible to regulators, advocates, and the public. Higher levels of regulatory attention will be required to create the right rewards and incentives to optimize the amount of infrastructure-building and implementation for DR. Therefore, these activities may move forward more slowly.

Where is the push for DR coming from in the political environment?

- A few utilities (e.g., PG&E, Ontario Hydro) have taken major steps to integrate DR into their planning framework. These utilities may promote a rate/regulatory environment where they are rewarded for efficient grid operation, including use of DR. They will also promote an environment where clear rules are set for them to operate or contract directly for distributed generation and sell power. This is the case in California, for example, where Discos can sell power to the power pool as well as market power services to their customers.

- Environmental advocates have been taking up the cause of DR, largely by pushing for pilot studies. Hopefully, this paper will help guide advocates to press for changes which impact the fundamental barriers both to effective pilots and effective programs and policies.

- Some regulators have also prodded utilities to experiment more with DR and to integrate it into their operations. The most common activity has been to encourage pilot projects, not to identify or help create the conditions in which DR will thrive.

- In some states, (e.g., California) there has been political pressure for the utility system to offer performance contracting Energy Service Companies (ESCos) a higher price, based on the value of DR to the system. This has generally led to confusion because a simple system for pricing DR is difficult to establish, and a universal system is inappropriate. Furthermore, as discussed above, it is not clear that free-market efforts to reduce load on targeted feeders, if not closely coordinated with utility planning, have any DR value. We know of no state where the art of DR planning within the utility has advanced far enough, and is accessible to the public enough, for this type of integration of the ESCo community into DR planning to occur.

In general, among policymakers and supplicants to the regulatory process, there is significant confusion about the difference between DR projects and DR planning systems, and what it will take to make either work. Thus, utilities who believe strongly in DR have proceeded on their own, and most utilities have taken no, or only superficial, action.

5.B.3. Lack of Access to Good Models

While a handful of utilities are beginning to restructure their operations to take advantage of DR, the tools, experience, and financial analysis underlying this transformation are becoming public only in fragmentary form. This, in part, reflects the belief among the leaders that they are enjoying significant competitive advantage from use of DR. It also stems from the proprietary nature of many consultant-based DR tools and methods. In this environment, it is difficult to say how far even the leaders have advanced.

These problems can be addressed only if regulators and advocates demand that the precepts, justification, and analysis for DR become public issues, subject to public critique and scrutiny. This is fully compatible with the desire of leading utilities and consultants to press their methods to competitive advantage. It is possible to discuss the logic of planning methods without surrendering property rights or describing detailed code. It is also possible to review case studies in confidence, without subjecting every local T&D plan to full regulatory review, and without breaching confidences. In other areas of planning, such as Integrated Resource Planning, it has been demonstrated that emulation of the leading utilities is possible with full respect to intellectual property rights. The leaders tend to profit and thrive by renting out their experience, using public forums to demonstrate the value of their tools, and through the quality of their own experience-based execution.

Furthermore, it is clear that DR will spread only if there are leading exemplar Discos whose practices, systems, and models are well-understood by others (even if available for use only at price).

6. RECOMMENDATIONS FOR REGULATORY AND ADVOCATE ACTION

The executive summary of this paper provided a synopsis of market barriers and policies to address them. This section of the paper suggests a list of complimentary projects to further DR.

This list of recommended actions includes a balance of focused activities to create leadership models for DR in a few locations, and more incremental actions that can be encouraged on a widespread basis. The "leadership actions"will detail and test some of the more speculative proposed solutions presented in this paper. The objectives include gaining more experience, creating a policy framework for DR, and gaining the awareness and attention that is needed by showing the importance of DR to policymakers.

Most of the recommended actions should ideally be undertaken in a collaborative or other cooperative arrangement sanctioned by regulators, involving regulatory staff or consultants, utilities, and advocates, by which lessons learned will be made public and publically critiqued. Without this environment of critical dialogue, DR may not evolve or become accepted as quickly, and it may not evolve in a way which maximizes benefits to the public.

6.A. BUSINESS, FINANCIAL, AND PUBLIC BENEFITS ANALYSIS OF DISTRIBUTED RESOURCES

Nationwide, there is a need for at least two to three separate projects to further flesh-out the implications of DR, for both T&D companies (Discos or T&D operations of integrated utilities) and for the public. Suggested topics of exploration would include:

1. Describe the financial structure of the distribution service business. How do Discos make money? How does that relate to T&D capitalization? What are future management trends which would impact DR?

2. Define some practical and effective distribution rate structures. The business interest of post-restructuring Discos in DR largely depends on their T&D rates. There is a need to describe rate structures which make business and public policy sense with respect to overall Disco operations, and also specifically for DR.

3. Develop quantitative load and financial scenarios showing possible futures for:

    a. The potential scale and impact of customer-driven development of distributed generation (considering markets for high-reliability power, economic bypass, etc.).

   b. The potential for economic T&D company investment in energy efficiency and generation improvements (through targeted projects or incentives) to reduce T&D costs.

4. Using the information developed through the steps shown above, assess the importance to T&D companies and their customers of pursuing investment in alternative distribution resources. Consider year-to-year profitability and long-term financial risk, debt loads, environmental effects, and other key financial and public purpose indices.

6.B. DISTRIBUTED RESOURCES PILOT PROJECTS

Nationwide, there is a need for projects with several distribution utilities,covering a range of financial and geographic situations, to:

1. Conduct pilot projects to develop and test tools for planning and implementing investments in alternative distribution resources. These efforts should include:

   a. Methods for screening T&D improvement projects for good DR candidates.

   b. Experimental methods for quantifying and considering benefits not considered in established methods.

   c. System-wide planning tools for considering tradeoffs between T&D improvements and DR (including testing and refinement of existing models).

2. Evaluate experience to date of pilot DR investment projects representing a broad range of anticipated investment opportunities, including both energy efficiency and distributed generation:

   a. Across diverse distribution load conditions.

   b. If possible, utilizing a range of investment strategies, including utility-controlled development, local rates, and/or posting a market price for others to respond to a need.

   c. To the extent possible, integrated and coordinated with local public purposes energy-efficiency programs.

   d. Where warranted, engage in new pilot projects to reflect new technical and analytic opportunities and extend the range of experience.

6.C. DEVELOP RATIONAL AND FAIR STANDARDS FOR DISTRIBUTED GENERATION

In cooperation with several distribution companies and distributed resource development companies, develop:

1. Model distributed resources grid interconnection standards (e.g., reliability, power quality, isolation) for different sizes and types of local power. Also, consider how to address positive contributions to grid reliability from some DRs.

2. Model tariffs for wheeling power and local generation support within distribution systems (back-up power, buy-back rates for local generation, etc.).

3. Policies for setting localized rates to reflect differences in cost-of-service and timing-of-costs by distribution area (to encourage appropriate local generation).

6.D. DEVELOP POLICIES FOR GENERATOR/DISCO COORDINATION OF LOAD MANAGEMENT

In at least two states or regions, organize a team of stakeholders (Discos, distributed generation developers, etc.) to:

1. Define issues and needs for Disco/Genco coordination of investment and operational activities, both to pursue complementary economic interests in peak management and to avoid shifting load onto each others' peak periods.

2. Explore interactions with public-purpose conservation funding (be it implemented by the Disco, a central entity, or someone else).

3. Describe possible avenues for coordination and joint investment in projects which benefit multiple parties.

4. Define regulatory issues and barriers to coordination; define solutions which maximize social benefits from coordination without impeding market competition for power sales.

5. While policy is being developed, regulators should allow some limited-scale development of power by Discos for on-site use and/or resale to wholesalers or power exchange (not to retail customers), as long as the T&D deferral benefits are clear.

6.E. DEVELOP FULLY INTEGRATED DR CAPABILITY AT SELECT UTILITIES

Work with "concept leader" utilities to take DR from the pilot stage and integrate it into their system-wide processes for project planning, economic analysis, implementation, and financial impact tracking.

6.F. ENCOURAGE MOVEMENT TOWARD DR CAPABILITY AMONG OTHER UTILITIES

Regulators and advocates should:

1. Respond positively to utility-initiated DR initiatives which show real stepwise improvement, while taking care not to endorse superficial efforts which lock in bad policies.

2. Give utilities some latitude to experiment and gain DR experience before considering policies that encourage all DR delivery activities be taken over by the private sector.

3. As a key first step, prod utilities who lack hourly data on substation loads to invest in the metering necessary to collect this data and in the analytic capability to utilize it, starting with likely areas for future T&D system investment. Allow utilities to recover these costs from rates.

4. Also encourage utilities to gain customer market data and analysis capability which will build a base of capability for DR planning and implementation. Discourage utilities from dismantling their customer-service organizations once restructuring puts them out of the generation market.

    - Encourage the development of customer cost-based reliability criteria for T&D enhancements.

5. In states undergoing rate structure redesign, encourage regulators to develop rates which allow for cost recovery and reward for research and development which is clearly tied to future public benefits. This will create an avenue to encourage DR research.

6. Ask utilities to improve their justification for T&D investments (in terms of the systems and logic used, not project-by-project), and to show how they are considering DR alternatives; encourage and reward pilot activities that show progressive improvement in standards for documentation, load forecasting, customer generation forecasting, capital investment justification, consideration of critical non-traditional benefits, etc.

- To encourage more sophistication among utilities, advocates and regulators will need to develop improved sophistication in DR issues.

6.G. DEVELOP COORDINATION MECHANISMS FOR NATIONAL DEVELOPMENT OF DR

Establish an effective mechanism for tracking and coordinating collaborative efforts with utility industry work, through EPRI or other entities.

HELPING DISTRIBUTED RESOURCES HAPPEN:

A Blueprint For Regulators, Advocates, and Distribution Companies

APPENDICES

APPENDIX A:

DISTRIBUTED GENERATION IMPACTS ON DELIVERY SYSTEM

Depending on size of the DGs, they can feed into the utility system on the primary distribution feeder, at the distribution substation, or on either the sub-transmission system or the primary transmission system via large power transformers. Sometimes, very small generators feed into the utility single-phase or three-phase secondary systems (i.e., systems with nominal voltages of 600 V and below).

Electric utility distribution systems are not inherently designed to accommodate distributed resources. They are normally configured so that primary (customer-level) lines have many characteristics that are peculiar to only that level. However, DGs have existed for years on many utility systems with no apparent problems. The reason for this is partly the fact that the individual units and number of units were very small and had little effect on the system. A large influx of DGs on the distribution systems is a cause for some concern, especially when their capacity approaches the capability of the feeder. Specific issues are discussed below.

A.1. DISTRIBUTED RESOURCES AND FAULTS

Impact of Distributed Generation on Grid Operation

When generation sources are connected to the primary feeder circuit, they can significantly alter the characteristics of the feeder circuit, impacting operation and performance during normal and faulted conditions. Specifically:

- The transformer connections selected by some users for connecting a local generator to the primary feeder creates a ground source for the feeder, complicating the overcurrent[19] protection of the primary feeder. Overcurrent protection devices downstream from the fault can perceive short-circuit currents.

- The overcurrent protective devices in series between the substation and fault no longer see the same current, thereby complicating the coordination of the overcurrent protective devices.

- The grounding of the primary feeder circuit may be degraded when DG is added, depending on the winding configuration of the transformer connecting the generator to the primary feeder.

[19] Overcurrent essentially means an amperage overload.

Even though the utility may open a breaker, recloser, or switch in a primary feeder, the feeder downstream from the open device may become energized from the DG source. Normally, linemen would not expect the line to be energized. This necessitates review of operating and safety procedures for primary feeders with DG.

In a recent review of DR experience from Rocky Mountain Institute (RMI),[20] it was asserted that most of the technical issues associated with DG integration can readily be addressed through thoughtful application of DGs, combined with fairly low-cost adaptations to grid control. The same study asserts that the needed improvements to grid control either are off-the-shelf or easy to develop from current technology and practice. This is a complex technical area where certainty will grow with added experience and evaluation.

However, the review also asserts that current standards for grid reliability are, in some cases, biased against DG, by tolerating levels of power quality degradation from T&D components which are not tolerated if provided by alternative DG equipment. They also suggest that some grid integrity standards and protocols place most demands for quality on the new generation resources even where the same ends could be met more inexpensively through minor improvements or adjustments to local T&D equipment. The arbiters of power quality control within the T&D engineering community are just beginning to think clearly about the implications of T&D versus DG tradeoffs.

The authors of this paper have not thoroughly researched the RMI claims, but believe that, at a minimum, they point to areas where further reflection and innovation in grid power quality and reliability management are needed. As discussed in the *Power Quality* section of this paper, local generation will be increasingly common in any event. T&D system operators will need to deal with this phenomenon reasonably, equitably, and safely.

Fault Protection

A fault is an interruption of power delivery or a major change in current, voltage, or alternating current cycles. It can be caused by a line break, lightening, an overload, a local transformer failure, or many other situations. Understanding faults is important to DR, because DR require changes to the way the grid deals with faults, and also provide some advantages and disadvantages with respect to the number of faults.

In a radial primary distribution system that does not have DG, fault protection is provided by isolation of faults on the grid, using a combination of fuses, mechanical, electronic, and hydraulic devices. These devices are coordinated so that the circuit is broken at the control point closest to the fault, to minimize the number of customers experiencing an outage from a fault. However, on radial feeders, customers "downstream" of the fault are interrupted because there is often no alternative conduit for power.

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[20] Lovins, Amory B., and Lehmann, André, op. cit.

Because many faults are self-correcting, many fault protection devices incorporate automatic re-closing. This allows customers to experience only a momentary outage.

In the event of a fault upstream of a DG, continued operation of the DG can create problems. If the DG is inadequate to meet all loads downstream of the fault, voltage could fluctuate, damaging equipment. Additionally, loads down-stream of a fault can be a hazard to repair crews if they do not know that the DG is present.

Generally, DGs are controlled so that either they stop operating in the event of a fault, or they are isolated on a local circuit. Utility personnel are aware of these issues and have added safety procedures related to possible isolated generation issues. Standards for the installation of DG resources are being utilized today in backup generation installations.

APPENDIX B:

LOCAL TRANSMISSION PLANNING - INTEGRATING FLEXIBILITY

The amount of power that may be delivered by the transmission system to a given point in that system is governed by the current system topology (i.e., layout of equipment), system stability limitations, and conductor thermal limits. Additionally, in some local situations, future transmission circuit-loading limitations may be instituted, based on concerns about radio and TV interference, audible noise, and, more speculatively, impacts of magnetic fields on humans and other living things.

From a transmission system perspective, the capacity limits from the preceding factors are not as inflexible as one might initially think. Utilities are experimenting with "uprating" of transmission conduits, based on a more sophisticated assessment of weather, duration of peak, and prior loadings, all of which impact real-world capacity. Where "uprating" is possible, it may sometimes be a low-cost alternative to both transmission upgrades and DR projects. It is important to note that uprating requires hourly load data which, as discussed above, is also useful for DR planning.

APPENDIX C:

ROLE OF DISCOS IN LOCAL GENERATION

Most deregulation schemes under consideration in the U.S. assume corporate or functional separation of Gencos from Discos, in order to prevent self-serving promotion of the "home product" by Discos, at the expense of fair competition. Yet, Discos will be a primary beneficiary of DR and a key party in the definition of value from T&D deferral. This raises the issue of whether Discos should be allowed, and even encouraged, to own some local generation where it avoids or defers T&D capital costs.

In theory, Discos would not need to own generation to benefit from its strategic placement within the grid. If Discos offered a stream of payment for anyone who sited a plant with certain performance characteristics in a specific area, an independent power developer could find appropriate siting, build a plant, and collect a premium payment from the utility on top of power sales revenues. However, several logistical and infrastructure issues make this seem less likely:

1. For reliability reasons, Discos cannot defer a T&D upgrade without a firm alternative in hand. This means that the utility would need to place a request for plants, receive bids, select a winner, and receive a satisfactory construction schedule and adequate financial assurances of on-time construction before the critical path for T&D construction begins. Until the process reaches this stage, it will not be known whether there is, in fact, a DR alternative which costs less than the T&D alternative.

   The utility could, in some cases, utilize portable capability (transformers or generators) to extend the critical path to allow time for the bid. However, temporary fixes have significant costs.

2. The market for power is likely to be highly volatile during the first several years of competition, with many players appearing and then either leaving the market or going bankrupt. To supplant T&D facilities, local generation must be absolutely reliable. What will the backup strategy be if a local generator contracts with a utility for “local generation payments” but then runs out of operating capital? What happens if the local generator finds that the cost of the local plant, even with the Disco payments, is not competitive?

3. Time-lines for distribution upgrades are often fairly short, leaving little time for the process described above.

4. Because DR bidding processes are not yet common, there is not yet a competitive group of generation and the DSM service providers who are prepared to respond to a bid and

provide generation or efficiency coordinated with utilities, on utilities short schedules, with sufficient reliability to suppliant T&D improvements. Thus, response to early requests of this sort are likely to be both slow and more expensive than they would be in a fully-developed market. There may be a need to proceed through an experimental phase, and then an industry-building phase over several years, before the logistical issues are worked out and the price reaches a reasonable equilibrium.

5. Under cost-of-service regulation, it is unclear that payments to a power plant developer for a "service" would receive regulatory treatment (i.e., compensation from ratepayers) on parity with utility capital investments. In other words, without explicit rules that have not yet been developed, Discos may fear losing profits by farming out generation instead of building more grid capability.

6. The scale of some investments (hundreds or even tens of thousands of dollars) may not justify the administrative costs of a bidding process.

7. Discos will need extensive and direct experience with DR projects to gain familiarity with the ways that various forms of DR interact with the system. Discos need to achieve a technical comfort level in order to maintain their responsibilities for reliable and efficient grid operation. While this may be possible through interaction with independently-owned plants, the separate ownership creates opportunities for early shake-down problems to turn into financial and legal quagmires instead of research and enhancement opportunities. If early plants are owned by Discos, it will be contractually and conceptually simpler to treat them as “part of the grid,” and invest in enhancements in grid integration, on an experimental basis, without wrangling over issues of financial culpability. In-house ownership will also help T&D engineers overcome initial anxiety over reliance on what for many will be novel approaches to reliability issues. It is psychologically difficult to rely on something new to meet one's professional responsibilities, but even harder to cede control to a new player with a new approach. While T&D planners will need to "get over it" eventually, DR will move faster if T&D planners feel that they have some control over early experiments, reducing the perceived risk.

8. In many instances, the least-cost approach to T&D deferral will involve both energy efficiency investments and generation. While it is possible to respond to a bid with such a package of services, the conservation elements will often be attractive only if societal generation deferral benefits are considered along with local T&D benefits. In states where the utility is the wires-charge fund administrator for efficiency, it will be logistically simpler for the utility to combine and optimize the elements of both generation and efficiency, if the utility can specify and own the generation. This is not an insurmountable issue; coordination agreements can be developed, and conservation services can be bid alongside generation. However, until there is more experience with

this type of T&D deferral project, and an established market to provide combined services, the bid process will be cumbersome and may not lead to ideal responses.

While the points listed above argue for heavy Disco involvement in early DR projects, this contradicts the legitimate desire of many parties to assure that there is functional and market separation between competing generators and monopoly Discos. In the long run, it should be possible to create effective non-Disco mechanisms for providing local generation. In the short run, the solution may be to allow and reward utility ownership of local generation facilities only where the following conditions can be demonstrated:

1. The generation facility meets a demonstrated need to defer T&D investments by the Disco, based on a public, defensible planning process; and

2. The power is not sold directly to customers in the Disco service territory, but is sold to other wholesalers (independent in ownership from the Disco).