Regulatory Assistance Project
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Focus On Distribution System Regulation: Avoiding Costs And Capturing Values

Although distribution is a fully-regulated monopoly function, its working details are not always well understood. Electricity distribution systems play a critical role in reliability, system growth, demand management and response, distributed generation interconnection, and customer metering and billing. In light of the over $5 billion invested nationwide every year in distribution systems, distribution planning and investment practices probably warrant greater attention from regulators than they currently receive.

Regulators need to understand what drives distribution system economics and how decisions made about investments affect other parts of the system. In this Issuesletter, we suggest three key actions for improving distribution utility regulation:

1. Assess the utility's existing distribution system planning process;
2. Develop clear policy objectives for distribution utility planning that take all available resources into account; and
3. Adopt rules of practice that include periodic review of plans and investments.

Step 1: Understanding The Distribution System And Its Planning Process

Regulators are accustomed to dealing with utility system planning issues in aggregated terms. They identify system peaks and the resources to serve those peaks. Commonly the approach to meet peak demand has centered on generation and transmission supply that have a planning horizon of five, ten, or even thirty years. Distribution planning, however, offers a different process, one where planning can take place on a shorter time scale, sometimes as little as weeks or months out to three to five years and only rarely as long as seven years.

Examples of short time horizon planning include decisions by landowners to develop land for commercial or residential use that suddenly create the need for distribution system expansion where none existed before. The construction or expansion of a high-tech manufacturing plant, even in an existing industrial park, can also create a new need for high reliability and high power quality.

Except for reliability-based investments, most distribution system investments are driven not by system peaks but by peak loads, *i.e.,* peaks on individual transformers, feeders, and lines. These peaks may, and often do, occur at different times of the day or year than do system peaks and may grow even when the total system peak declines.

In response to expansion needs, distribution planning usually focuses on one of three needs: (1) replacement of a plant that has reached the end of its service life, (2) upgrading of a plant that can (or shortly will) no longer meet customer needs, and (3) greenfield expansion of the system, typically in suburban growth areas. The solutions to these expansion needs can be met not only with equipment similar to

Distribution System Cost Data

A review of the cost of expansion of the distribution system for all utilities filing a FERC Form 1 for the period 1994-1999 suggests that the effective cost per MW of load growth of wires and transformer upgrades and expansions can be both high and variable. The average marginal costs for transformers and substations ranged from virtually zero to over $3,500 per kW. The average for the group (excluding negative growth companies) was $136 per kW, with a standard deviation of over $356 per kW. For lines and feeders, the marginal costs ranged from virtually zero to as high as $19,483 per kW. The average cost was $872 per kW, with a standard deviation of over $2,800 per kW. To put these figures in context, consider that the cost of new gas-fired generation falls in the $600-$800 per kW range. The potential costs of distribution system upgrades and expansions are not just high, they are extremely expensive.

In addition to high marginal costs (for any given company), the costs of individual projects (within a particular company) can vary by a factor of two or sometimes even more. This means distribution system projects must each be analyzed and ranked in order of cost as part of the design, implementation, and regulatory processes. In most cases, regulators have no mechanisms to fully monitor and evaluate these costs. For more information about distribution system costs, see Distribution System Cost Methodologies for Distributed Generation, Wayne Shirley, September 2001 available at <http://www.raponline.org>.

what is currently in use but also with new grid technologies and investments on the customer side of the meter. Regulators need to understand the factors behind each of these types of distribution projects and, more importantly, the trade-offs between traditional solutions and their alternatives.

Distribution Cost Basics

For our purposes, distribution system costs can be divided into two groups: (1) transformers and substations and (2) lines and feeders.[1] Transformers and substations are both the first and intermediate interfaces between transmission and customer-level service. Feeders generally connect the highest voltage transformers to intermediate level transformers. Lines carry the lowest distribution voltage power to individual customer transformers and drop lines.

High and Low Cost Areas

Costs for new generating technology are fairly predictable and, given today's moderate new unit sizes, can be well matched to a utility's aggregate load growth. It is much more difficult (particularly in the short term) to match distribution system investments to load growth. In fact, while greenfield expansion of the system often requires a parallel expansion of generating supply, distribution replacements and upgrades can be required even when total system load is declining.

There are a number of factors that influence the relative expense of distribution investments. One of the most critical drivers is the rate of growth on the affected part of the system. A line that is at or near its capacity may need to be replaced with a higher capacity wire or upgraded to a higher voltage. If load on the line is growing at a rapid pace, the levelized cost of the investment may be reasonably low because it can be spread across more consumption units within a short period of time. On the other hand, if load is growing slowly, the levelized cost can be several magnitudes above the average embedded cost of the system, sometimes hundreds of thousands of dollars per kW, and, on occasion, even millions of dollars per kW. Greenfield expansions can likewise be drastically affected by the rate of growth available to absorb the new investments. "Build it and they will come" strategies work only if "they" come relatively soon.

1 Meters and other customer premises equipment are an additional category of distribution costs. However, these costs are determined principally by the nature of the customer and do not vary in any significant way as a function of distribution system solutions.

Geographic conditions can also drive costs. Upgrading major feeders in an underground, congested urban setting can be expensive, especially when compared to installing an overhead feeder in a suburban environment. Mountainous or rocky terrain is more expensive to work in than flat plains or sandy soil. Regardless of the general characteristics of a utility system, almost every system will have a combination of relatively high- and low-cost areas.

Finally, the technological "fix" for a given problem is critical to cost determination. Some solutions are almost cost free. For example, when faced with capacity constraints or high losses, loads on one substation might be lightened merely by throwing a switch that reroutes power to the same load, using an alternative path. Other solutions, such as installing an underground "super feeder" in an urban downtown or installing a major new switching station that requires numerous related investments in new feeders and transformers, might be extremely expensive.

Distribution utilities should be required to report the nature of the distribution system investments they are making (or plan to make) and identify specific projects that are particularly high in cost, especially as compared to the magnitude (*i.e.,* high $/MW) of the problem being solved. For some utilities, it may be that only a few, well-defined parts of the system are high cost. For other utilities, it may be that a

Distribution System Regulatory Checklist

Step 1: Understanding The Distribution System And Its Planning Process

- ➜ Identify how costs are calculated and allocated to new projects.
- ➜ Evaluate the decision-making process used by the utility to initiate new distribution system projects.
- ➜ Identify and review most or all of the utility's distribution system expansion and improvement projects.
- ➜ Identify high and low marginal cost areas on the distribution system.
- ➜ Identify existing problem areas on the distribution system and the utility's strategies for solving those problems.
- ➜ Identify the environmental effects of resource choices.
- ➜ Identify available resources, conduct supply- and demand-side comparative cost analyses of potential resources, and determine optimal combinations of resources.
- ➜ Consider the effect of distribution planning choices on the balance of supply and demand resources.

Step 2: Development Of Policy Objectives

- ➜ Provide a clear statement of the distribution utility's required decision criteria in operating and expanding the distribution system.
- ➜ Make sure revenue requirements and rate design reflect distribution system costs.

Step 3: Rules Of Practice With Periodic Review

Adopt rules governing the distribution system, including:

- ➜ A Distributed Generation Interconnection rule that allows for easy integration of customer-owned resources.
- ➜ An Environmental Emissions Rule (see the Model Distributed Resources Emissions Rule).
- ➜ A Reporting and Approval Rule requiring the regular (preferably annual) filing, public review, and commission approval of the utility's distribution expansion, upgrades, and investment plan.

Overcoming Distribution System Engineering Cultural Bias

Distribution engineers have, for decades, largely employed the same methods to plan and expand the system and to solve specific problems. Because of safety and reliability concerns and because of the industry's culture of monopolistic control, distribution utilities have not typically embraced new or innovative ways to solve problems, especially where solutions may lie on the customer's side of the meter. Fairly rigid and traditional engineering criteria have driven the decision-making process. Engineering solutions usually result in bigger wires and transformers or other system add-ons, such as capacitors. The overriding need for adequate and reliable delivery, while important, tends to inhibit the adoption of innovative and less costly means of serving customers.

Regulators should make clear to utilities that energy efficiency, load-side generation, and load management must be considered as part of a prudent planning process. Emerging distributed generation technologies likewise may offer more economic alternatives to traditional distribution system solutions.

It is important to understand that, while demand-side alternatives, such as energy efficiency, load management, and distributed generation may not permanently avoid distribution investments, they can still provide meaningful value by delaying more expensive investments – the longer the delay, the greater the value. Also, some solutions, like distributed generation, may be portable and can be redeployed in other parts of the system when no longer necessary in their original application. In this way, a single investment will continue to deliver value over its entire life, even though it sequentially defers different investments, at different points in time. The challenge is getting utilities to incorporate these assessments into their daily planning routines.

more generalized area (or areas) can be classified as high cost.

Existing Problem Areas

"Problem" areas may also exist on the system; often they may be quite well known. These might be areas that suffer from chronic voltage support problems, experience high losses, are adversely affected by loads with poor power factors, or have a high number of outages. In these cases, the distribution investments are likely to be less oriented toward bigger (or newer) wires and transformers and more toward system "add-ons" like capacitors or local generation. Regulators will want to become educated about the causes of these problems and about the engineering and planning solutions that utilities typically use to address them. Regulators will want to explore alternative solutions, including changes in customer usage patterns (*i.e.*, energy efficiency, load management, innovative rate designs, etc.) or improved customer equipment.

Environmental Impacts Of Resource Choices

The technology and configuration choices made at all levels of the system will have both the short- and long-run environmental impacts. One of the important matters to consider when reviewing both traditional and non-traditional planning solutions is the environmental consequences of the alternatives. Not all new technologies are equal, and many are not environmentally benign.[2] For example, a decision to rely on customer-owned emergency generation for peaking power might result in drastic increases in the operation of high-emissions diesel generation. This often occurs on very hot days that coincide with already high power plant emissions, especially when power comes from older resources, installed over the past several decades. On the other hand, energy efficiency avoids emissions altogether. The environmental impacts of alternatives should be disclosed and considered in the system planning process.

Effect On Markets

System expansions plans that rely heavily, or exclusively, on traditional central station power

2 For more on the environmental impacts of distributed generation, see *Model Regulations for the Output of Specified Air Emissions from Smaller-Scale Electric Generation Resources,* Distributed Resources Emissions Working Group, available at <http://www.raponline.org>.

also tend to rely heavily on associated transmission and distribution system expansions or upgrades to deliver power. Failure to include these costs as part of the price of central power generation creates an implicit subsidy for such supplies. This is especially troublesome when there are higher emissions than would occur with distributed resources such as energy efficiency or combined heat and power.

Step 2: Development Of Policy Objectives

After the facts about distribution investments are understood, regulators are well positioned to consider a policy framework within which utility managers can work. Perhaps foremost, utilities should consider all viable approaches to distribution system expansion and improvement. A clear standard of prudence encompassing both supply- and demand-side solutions should be applied. Preferably, this standard will be based on least-cost planning principles.[3]

Revenue Requirements And Rate Design

As the economics of the distribution system become more apparent, regulators can consider whether traditional revenue requirement and rate design policies further or thwart prudent planning and expansion of the system. Because customer-side options in the form of demand response, energy efficiency, and distributed generation can all be at odds with the utility's profit incentive, special attention should be paid to how the utility's revenue requirements are determined and recovered.

As long as utility profits are directly tied to throughput, the utility will have an overwhelming incentive to prevent energy efficiency, load management, and distributed generation (on the customer-side of the meter). Either revenue cap regulation or lost revenue recovery mechanisms can eliminate this incentive.[4] By making

Capturing The Value Of Demand-Side Resources Through Customer Credits

There are a number of situations where installation of distributed resources would save money for both the utility and all customers. Inducing customers to make use of distributed resources may require new approaches to rate design.

For example, if a new commercial facility, such as a mall, is built within the area served by an existing distribution system, the additional load from that facility may, under traditional supply-side-only approaches, require significant upgrades of the distribution system. However, in this situation, a variety of demand-side resources may be deployed to avoid or reduce the wires and transformers upgrades. These might include working with the builder to embed greater efficiency in the new facilities, employ energy storage systems, or install distributed generation.

Often, the customer may be unable or unwilling to bear the investment burden and operational cost of the required distributed resources. Yet, in the absence of these resources, the distribution utility will be forced to incur the higher total costs that are often borne by all customers.

The use of special distributed resource credits can encourage customers to install needed resources in the high-cost parts of the system or as part of a customer-specific development, thereby avoiding more costly investments in distribution. This helps overcome customer resistance to investment in distributed resources and secures the investment value for the utility and its customers.

For more information see Distributed Resource Distribution Credit Pilot Programs: Revealing the Value to Consumers and Vendors, David Moskovitz, September 2001, available at <http://www.raponline.org>.

3 See *Portfolio Management: Protecting Customers in an Electric Market That Isn't Working Very Well,* Harrington et al., The Regulatory Assistance Project, for The Energy Foundation and the Hewlett Foundation, October 2002, available at <http:www.raponline.org>.

4 For a discussion of the critical importance of addressing the throughput problem, see *Profits and Progress Through Distributed Resources,* David Moskovitz, 2000, available at <http:www.raponline.org>.

use of such mechanisms regulators can stake out a clear position that cost recovery is tied to making the most economic choices between wires and transformers or demand-side solutions.

Step 3: Rules Of Practice With Periodic Review

Regulators need to develop and adopt new or modified rules for the distribution utility, written in light of the policy framework sketched out above. Regular reporting and disclosure of distribution system expansion plans are key to assuring that alternatives are being fairly and systematically considered. No less than once a year the utility's distribution investment projects should be disclosed to the regulator and the public. Historically, annual rate cases provided the opportunity to examine such plans, though issues of greater controversy generally pushed distribution plans out of view. With rate cases occurring with less frequency, implementing this regular reporting process assures adequate attention to quality distribution planning. Preferably, the customers (or any third party) should be given an opportunity to comment on plans and offer alternatives, perhaps in a competitive bidding regime. It should be made clear by the regulators that plans must include an assessment of long-run marginal costs, thus allowing for easy comparison across alternatives.

Perhaps most important is the development of an analytical discipline that is routinely applied by distribution system operators. Where the utilities remain vertically integrated (and where operators of unbundled distribution systems also function as the primary default service provider), the job will be made easier and can be readily adapted to the traditional regulatory process. For other configurations, regulators will need to develop a review process that assures that supply-side acquisitions are conducted in a way that takes account of distribution system costs and provides a means for evaluating alternatives to those costs. Utilities need not only to understand the economic trade-offs, but they need also to be held to a standard of conduct that requires that those trade-offs be taken into consideration.

Finally, adequate skills are needed within the regulatory agency. Distribution system costs have rarely been the focus of regulatory scrutiny. Staff will require additional training and direction to fulfill the regulator's responsibility of assuring least-cost system expansion and upgrades. While much can be borrowed from integrated resource planning, distribution system analyses will nonetheless require new skills and techniques.

Conclusion

Distribution system economics are likely to have increasing importance to both customers and regulators. It is important to take the opportunity to review this poor "step sister" of the system and assure that we are not investing needlessly in system expansions or improvements. Formalizing that review will help regulators, legislators, and customers attain a greater understanding of the issues involved and will enable them to develop appropriate policy objectives and the regulatory tools for achieving them.

Additional reading available on our website:

Portfolio Management: Protecting Customers in an Electric Market That Isn't Working Very Well, Harrington *et al.,* The Regulatory Assistance Project, for The Energy Foundation and the Hewlett Foundation, October 2002.

Accommodating Distributed Resources in Wholesale Markets, Frederick Weston, September 2001.

Distributed Resources and Electric System Reliability, Richard Cowart, September 2001.

Distribution System Cost Methodologies for Distributed Generation, Wayne Shirley, September 2001.

Distributed Resource Distribution Credit Pilot Programs: Revealing the Value to Consumers and Vendors, David Moskovitz, September 2001.

Charging For Distribution Utility Services: Issues in Rate Design, Frederick Weston, December 2000.

Performance Based Regulation for Distribution Utilities, David Moskovitz, December 2000.

Profits and Progress Through Distributed Resources, David Moskovitz, February 2000.

Model Regulations for the Output of Specified Emissions from Smaller-Scale Electric Generation Facilities, Distributed Resources Emissions Working Group, 31 October 2002.

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