Special Issue: Smart Grid Technologies

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Smart Grid Economics: Three Stories Bring up Issues

Stephen Chapel

To paraphrase Steve Jobs in his 2005 commencement address at Stanford University, this article tells three stories. That is it. The first story introduces the concept of Smart Grid and provides a context for what follows. The second describes the design configuration and cost structure of the distribution system (distribution consumes most of the power-delivery money and experiences most of the reliability events). The third outlines an analysis of the economics of distributed generation. The analysis has important implications for the evolution of the Smart Grid.

STORY ONE: THE SMART GRID CONCEPT

Concerning the technical details of the "Smart Grid," I have to admit that I am by no means an expert. However, I do know a lot about electric distribution technologies, the economics of these technologies, and issues of reliability and customer needs at the distribution level.[1] I also have studied the potential role that distributed resources have as part of the electric distribution infrastructure.[2] This article is devoted to documenting earlier work on the economic and institutional nature of the power-delivery system and the implications for the concept of "Smart Grid."

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Wikipedia defines *Smart Power Grid* as the following:[3]

> Smart Grid is a transformed electricity transmission and distribution network or "grid" that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability and safety of power delivery and use. Smart Grid is called several other things, including "Smart Power Grid," "Smart Electric Grid," "Intelligrid," "FutureGrid," etc. Deploying the Smart Grid became the policy of the United States with passage of the Energy Independence and Security Act of 2007 (Title 13). The law, Title 13, sets out $100M in funding per fiscal year from 2008–2012 in addition to other reimbursements and incentives. The Smart Grid is also being promoted by the European Union and other nations.
>
> The term **Smart power grid** may best be defined as using communications and modern computing to upgrade the current electric power grid so that it can operate more efficiently and reliably and support additional services to consumers. Such an upgrade is equivalent to bringing the power of the Internet to the transmission, distribution and use of electricity—it will save consumers money and reduce CO_2 emissions. (Wikipedia.com, retrieved August 25, 2008)

Based on the Wikipedia definition, reducing costs and emissions appears to be the stated problem that the Smart Grid concept is intended to solve. The question I have is the following: how is the Smart Grid going to save people money and reduce CO_2 emissions? Transmission and distribution are simply transport systems for electric power. Saving money could come from reducing the cost of the delivery system infrastructure. It could also come from improving reliability (thus reducing customer outage costs). Reducing CO_2 emissions requires reducing electric losses and accommodating clean technologies such as wind and solar.

How is the Smart Grid going to save people money and reduce CO_2 emissions? Transmission and distribution are simply transport systems. The Department of Energy (DOE) Smart Grid Web page states the following:

> Electric grid stakeholders representing utilities, technology providers, researchers, policymakers, and consumers have worked together to define the functions of a smart grid. Through regional meetings convened under the Modern Grid Strategy project of the National Energy Technology Laboratory (NETL), these stakeholders have identified the following characteristics or performance features of a smart grid:
>
> - Self-healing from power disturbance events
> - Enabling active participation by consumers in demand response
> - Operating resiliently against physical and cyber attack
> - Providing power quality for 21st century needs
> - Accommodating all generation and storage options
> - Enabling new products, services, and markets
> - Optimizing assets and operating efficiently
>
> (http://www.doe.energy.gov/smartgrid.htm)

I have categorized the DOE list according to fundamental issues addressed by each point:

- Self-healing—customer satisfaction through reliability/costs
- Participation in demand response—customer satisfaction through reduced costs and emissions
- Operating resiliently against physical and cyber attack—customer satisfaction through reliability/costs
- Power quality—customer satisfaction through reliability/costs
- Accommodating all generation and storage options—customer satisfaction reliability/costs and environment

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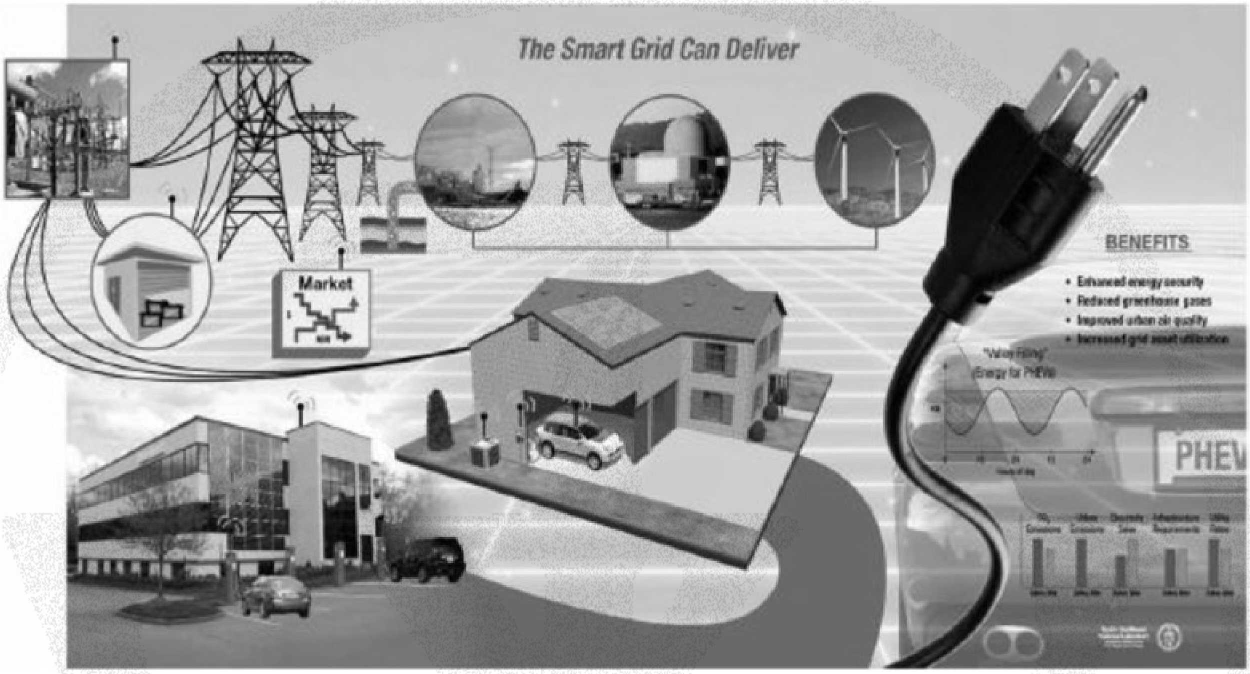

- Enabling new products, services, and markets—customer satisfaction
- Optimizing assets and operating efficiently—costs

Based on Wikipedia and DOE, it would seem that the Smart Grid concept is aimed at (1) improving the satisfaction of electric power consumers and (2) reducing environmental impacts, especially CO_2, associated with the use of electricity. The extent that these objectives are achieved will depend on the evolution and implementation of the concept. The two stories that follow will hopefully shed some light on the questions of evolution and implementation.

STORY TWO: DESIGN CONFIGURATION AND COST STRUCTURE OF DISTRIBUTION SYSTEMS

This story is about the economic nature of the electric grid system and what we know about customers' willingness to pay for changes to the nature of the system. This is partly about the physical nature of the system and partly about the cost structure. As stated previously, electric distribution consumes most of the power-delivery money and experiences most of the reliability events. It thus has the most potential for impacting/changing customer satisfaction.

Design Configuration

First, there is the design configuration part of the story. In an earlier life, I managed a team that worked on electric distribution planning issues. Part of the planning work was concerned with customer needs for reliability. In 2000, the team surveyed six electric utility systems (in the east and midwest). We also worked with three large electric utilities on the issue of planning for reliability. This work demonstrated that reliability depends very much on the configuration of the system and on the criteria used for planning the system.[4] The work also found that while most customers state that they would like to have greater reliability, very few, with some exceptions, are willing to pay the cost of any significant improvement.

> On average 88% of these systems are radial design. Five of the six systems were 85% or more radial. There was one exceptional system that was 50% radial and 50% network or grid. Most systems had very small numbers of customers on

loops. The largest percent looped was 10%.

Five of the six companies said that planning criteria did not differ by customer or region. However, additional comments qualify these statements. Several companies note that the system design inherently creates differences in reliability. For example, when urban systems are networked or use more loops they inherently create higher reliability (assuming that maintenance and other factors are comparable to those on radial systems). Further, several utilities noted that they classify loads with respect to criticality, and that this affects blackout order, restoration order, and contingency plans. (Ibid.)

In summary, at a high level, reliability depends on density of the system (urban systems are inherently more reliable than rural systems) and the configuration (radial systems are less reliable than looped systems; systems with short feeders [urban] are more reliable than systems with long feeders [rural]). The conclusion is that if you want a system to be more reliable, wait until the density increases and put customers on loops. However, loops are very expensive and difficult to maintain. Almost every utility we interviewed had some downtown loops and stated that the utility was trying to phase them out.

The lesson is that when it comes to reliability, configuration really does matter, but providing a configuration that significantly improves reliability is expensive. Given this fact, a central issue is: are customers willing to pay for the improvement?

When it comes to reliability, configuration really does matter, but providing a configuration that significantly improves reliability is expensive.

With regard to a self-healing Smart Grid, of which the loop is a current example, it will have to be inexpensive if it is to become a large part of the system of the future. The exception is for areas where customers place very high value on electric reliability.

Cost Structure of Power-Delivery Infrastructure

Electric delivery systems are capital-intensive. This fact has important implications for investment strategy and initiatives like the Smart Grid. There are two sides to this question. The first concerns the economic nature of the existing infrastructure. The second concerns customers' willingness to pay for changes to the existing infrastructure.

An earlier article documented the cost structure of the electric delivery system:

> Electric transmission and distribution fixed assets expanded rapidly following World War II. In current dollars, net capital stock increased from $1.3 billion in 1947 to $149 billion in 2006. During the same period, an index of net capital stock adjusted for inflation increased from 5.59 in 1947 to 118.28, a 21-fold increase. The index of net investment increased from 13.42 to 86.65 and has been above 80 since 1999.
>
> In November 1992, *Electric World* reported net investment for electric utilities as $26.7 billion with $13.5 billion in distribution and $4.5 billion in transmission. The magazine projected net investment to grow from $26 billion in 1992 to $34 billion by 2000 with T&D growing to $22 billion. (Chapel, S. [2008, February]. Transmission and distribution infrastructure management must enter a new age. *Natural Gas & Electricity*, p. 23.)

The statistics demonstrate that a lot of T&D equipment has been put in place, and the stock continues to grow. This stock is necessarily long-lived. Electric utilities are extremely asset-intensive, requiring about four dollars of capital in place for every dollar of annual revenue.[5] This high ratio translates into extra-long periods for capital recovery.

- The market will not allow quick capital recovery. While many industries can re-

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coup billion-dollar investments in three or four years, the recovery period for electric utilities is four to five times as long.
- Long-period capital recovery requires necessarily long economic lives and significant maintenance requirements.

The implication for the Smart Grid is the following: replacing the existing, long-lived, large power-delivery infrastructure with a system that includes what the Wikipedia definition anticipates (i.e., "robust two-way communications, advanced sensors, and distributed computers…"), if it happens at all, is going to take decades. This is true even if the dominant economic choice is the Smart Grid technology and design.

STORY THREE: DISTRIBUTED-GENERATION INVESTMENT DECISION MAKING

This story illustrates the economic s-based decision process of the electric power industry. This is the process that the Smart Grid concept faces. The electric power industry has had long experience with generation investment decision making and strategy. The analytic tools and underlying economic models have evolved over many decades. Every power company has trained individuals on staff that are experienced in generation investment planning. The same cannot be said for the power-delivery system.

The practice of investment planning and strategy for power delivery is in its infancy. There are at least two reasons. First, generation investments involve a few very large expenditures. Power delivery, especially distribution, involves many small investments. The large investments are visible and thus have long received close attention from regulators and senior management. The second reason was reported in an earlier article:

> [power delivery] asset management [investment planning] was largely reactive and decentralized. The systems were growing rapidly, and there was constant need to extend the delivery systems and hook up new customers. Also, during the period up to the mid-1970s to early 1980s, the systems were young to middle-aged. Maintenance and replacement was yet to emerge and an important consumer of time and money. (Chapel, S. [2008, February]. Transmission and distribution infrastructure management must enter a new age. *Natural Gas & Electricity*, p. 24.)

Power-delivery investments started to receive scrutiny in the early 1990s. Electric power restructuring created pressures to reduce costs. At the same time, the concept of distributed generation became popular. In the early 1990s, people became enamored with the notion of replacing part of the centrally generated power with power produced by small generators located in the delivery system.[6]

The early analyses were based on the notion of deferring large investments—T&D and generation—and little attention was paid to economic fundamentals. One of the fundamentals was staring us in the face. Practitioners of electric generation planning like to think about power plants as costing in the range of, say, \$250 to \$700 a kilowatt capacity. These practitioners are all well versed in the notion of economies of scale. Large power systems can take advantage of scale economies by investing in larger plants. The problem is that in the early phases of distributed-generation planning almost no one considered the cost per kilowatt or scale economies for distribution equipment such as power transformers and conductors. When we finally got around to looking at these variables, we were shocked. In many cases, distribution power transformers and conductors cost from a few tens of dollars a kilowatt to an upper range of around \$150 a kilowatt. In addition, in many cases the scale economies are even larger than for central station power generation. This realization forced us to address our basis for power-delivery investment decision making. In the process, a new set of investment decision-making analytics was created.

While developing the new analytics, a number of discoveries were made. First, it was learned that the decision is not whether or not an investment is needed but when—time to the next decision is an important concept. For example, we might make a large investment now and meet needs for a long period or we can make a small investment and revisit the decision in the not-too-distant future. Second, we learned that the rate that load is growing and its uncertainty determine the best investment strategy. Slow but uncertain load growth can make small investments with relatively high cost per kilowatt optimal. This is so because small investments defer big investments and allow you to revisit the decision as load growth evolves.

Third, the new analytics produced a decision tool to help with the power-delivery investment planning problem. That tool is the *Area Investment Planning Model*.[7] You can read about the concepts that underlie the analytics and software in a November 2000 Electric Power Research Institute report. That report also provides some key insights into the role of distributed generation. I summarize the insights here.[8]

The earlier work identified four real economic issues associated with power-delivery investment planning: fixed and variable costs, scale economies, load growth, and using distributed resources (DR) to defer big investments and hedge load uncertainty. Each is discussed briefly here:

> 1. Investment alternatives are characterized by their costs, fixed (capital) and variable (operating). These determine the actual cash flows. It is better to analyze these than approximate (if not fictitious) marginal costs.
> 2. Scale economies make for lumpy investment policies. This must be explicitly addressed and suggests that marginal considerations really do not adequately represent the actual cash flows.
> 3. Capacity expansion and reliability considerations are driven by load growth and demand on the system. Load is uncertain. Hence, we must address the consequences of this dynamic, uncertain, variable driving decisions. Utilities have been notoriously unable to forecast this variable with any accuracy in the long term.
> 4. The main economic benefits of DR are (a) the possibility of deferring large, lumpy investments and (b) the value of delaying an inevitable decision until the need for that decision becomes clearer.
>
> (Chapel, S. W., & Feinstein, C. D. [2000]. *Strategic role for DR in discos—An update*. [EPRI Report 1001162]. Palo Alto, CA: Author.)

Using the *Area Investment Planning Model* tool, an economic analysis was performed. The objective was to determine the conditions under which distributed resources (distributed generation) add strategic value to distribution system expansion plans. Two key assumptions underlie the analysis: (1) DR is an investment—it must compete with other investments; and (2) DR choice is based on local conditions (i.e., global or macro models cannot capture the value of DR investments). The approach considered feasible alternatives in terms of capacity and costs; the local area was described with respect to load level, load shape, and uncertain load growth dynamics; two kinds of local areas were defined, transmission constrained and infrastructure constrained; and the strategic value of distributed resources was measured with respect to their inclusion in the least-cost plans for each area. The specific detailed assumptions and data are in the November 2000 paper.

Results of the analysis are the following:

> Distributed resources are strategically valuable in local areas that are transmission constrained.
>
> - The value of distributed resources decreases as the local area peak load growth rate increases.
> - Distributed resources provide benefit by deferring the need for the large capital investment in transmission capacity.
> - Distributed resources provide benefit whether they are load-following or

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not and whether they are salvageable or not [i.e., when no longer needed, the units can be removed and used in another location].

Infrastructure constrained areas have limited strategic need for distributed resources.

- The value of distributed resources decreases as the local area peak load growth rate increases.
- The distributed resources provide benefit by deferring the need for the traditional infrastructure capacity investments and not by eliminating the need for the investments.
- In an infrastructure constrained area, distributed resources provide benefit if they are load-following and salvageable. Non-salvageable distributed resources do not provide measurable strategic benefits under the assumptions made in the study.
- Non-salvageable distributed resources with very low operating costs may have some strategic value in infrastructure constrained areas.
- If it is possible to reduce the uncertainty in forecasting future load growth based on observations of past load growth, then the strategic value of distributed resources increases.
- Reducing the capital cost ($/kW) of non-salvageable distributed resources is critical for such resources to play a strategic role in infrastructure constrained local areas.

(Ibid.)

The main points here are the following:

1. First, if an area is transmission-constrained and the area load growth is low and uncertain for the area, DR investments can sometimes be justified. The reason is that a transmission upgrade is a large expenditure and provides a lot of capacity that might turn out to be not needed or not used until far in the future. For transmission-constrained areas, the main benefit is deferral of the transmission investment. The value of that benefit may be as much as 50 percent. The load uncertainty hedge benefits are essentially zero.
2. Second, for areas where load is reaching the capacity of the local system and that are not limited by availability of transmission, DR is generally not a good option. However, if load growth is slow and uncertain and the generation or resource is load-following and can be salvaged, the investment may be a good choice. The cost of DR investments, dollars per kilowatt, is currently not competitive with traditional distribution infrastructure investments.

So what lessons does this distributed-generation story have for the Smart Grid? I believe there are two. First, costs matter, and if Smart Grid technology is expensive. it is going to have a tough time competing with traditional alternatives. Second, economic planning tools are critical for developing good investment strategy. The tools and principles exist. They should be used.

NOTES

1. Feinstein, C. D., Morris, P. A., & Downs, C. (2000). *Customer needs for electric power reliability and power quality: White paper* (Electric Power Research Institute [EPRI] Report 1000428). Palo Alto, CA: EPRI. and Feinstein, C. D., Hamm, G. L., & Morris, P. (2001). *A review of the reliability of electric distribution system components: White paper* (EPRI Report 1001873). Palo Alto, CA: EPRI.
2. Chapel, S. W., & Feinstein, C.D. (2000). *Strategic role for DR in discos—An update* (EPRI Report 1001162). Palo Alto, CA: EPRI., and Orans, R., Feinstein, C. D., Edmunds, T., Lamont, A., & Pupp, R. (1993). *Distributed utility valuation project (monograph)* (EPRI Report TR-102807, PG&E Report 005-93.13). Palo Alto, CA/ San Ramon, CA: EPRI/PG&E.
3. It is worth noting that this Wikipedia definition is categorized as blatant advertising (i.e., pages that exclusively promote some entity and that would need to be fundamentally rewritten to become encyclopedic). Note that simply having a company or product as its subject does *not* qualify an article for this criterion.
4. Results are Hamm, G. L. (2000, September). *Current distribution planning practices.* Unpublished report.
5. Kolbe, L. (1982, June). *The electric utility industries financial condition: An update* (EPRI EA-2446-ls). Palo Alto, CA: EPRI.
6. Feinstein, C. D. (1993). *An introduction to the distributed utility valuation project (monograph)* (EPRI Report TR-102461, PG&E Report 005-93.13). Palo Alto, CA/ San Ramon, CA: EPRI/PG&E.
7. EPRI. (2001). *User's manual: Area investment strategy model, version 1.6.* Palo Alto, CA: Author.
8. Chapel, S. W., & Feinstein, C. D. (2000). *Strategic role for DR in discos—An update* (EPRI Report 1001162). Palo Alto, CA: EPRI.