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Creating a Smarter U.S. Electricity Grid

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Starting in the late 1980s, federal and state governments began to restructure and deregulate some segments of the U.S. electric power industry. The basic idea was that the generation, transmission, physical distribution, and retail supply of electricity would be "unbundled" from one another. The physical distribution of electricity and the transmission of electricity would continue to be subject to state (distribution) and federal (transmission) regulation, while generation (wholesale competition) and retail supply (retail competition) would become competitive. To support this restructuring program, a number of regulatory and organizational changes were made or planned to create and manage wholesale power markets, transmission networks, and retail competition in an efficient manner.

These reforms spread quickly during the late 1990s. Then came the California Electricity Crisis (or the Western Electricity Crisis) of 2000–2001 (Joskow 2001; Borenstein 2002). The political reaction to this crisis put a virtual halt on additional states adopting restructuring and associated retail competition reforms. It also slowed efforts by the Federal Energy Regulatory Commission (FERC) to push forward its agenda to bring organized wholesale markets, integrating the efficient dispatch and pricing of generation supplied at different locations with the efficient allocation of scarce transmission capacity, to the entire country. FERC's efforts to rationalize the balkanized ownership and operation of transmission facilities by creating Regional Transmission Authorities (RTO) managed by Independent System Operators (ISOs) were also constrained. Today about one-third of the population has access to competitive retail supply alternatives, and

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about half of the generating capacity in the country is located in regions with organized competitive wholesale markets and transmission networks managed by independent system operators (Joskow 2006).

While efforts to refine the wholesale and retail competitive market reforms continue, public policy interest has now shifted to modernizing and expanding transmission and distribution networks. In particular, this paper focuses on efforts to build what policymakers call the "smart grid" by 1) stimulating investment to improve the remote monitoring and automatic and remote control of facilities on high-voltage transmission networks; 2) stimulating investment to improve the remote monitoring, two-way communications, and automatic and remote control of local distribution networks; and 3) installing "smart" metering and associated communications capabilities on customer premises so that customers can receive real-time price information and/or take advantage of opportunities to contract with their retail supplier to manage the consumer's demands remotely in response to wholesale prices and network congestion. While the smart grid is the focus of this paper, there are other important areas for modernizing and expanding transmission networks, including stimulating investment in new transmission capacity, especially "long distance" transmission facilities that span multiple states, and better integrating electricity demand into wholesale power markets.

A recent Electric Power Research Institute (2011a, p. 1-1) report uses the following definition of the smart grid:

> The term "Smart Grid" refers to the modernization of the electricity delivery system so that it monitors, protects, and automatically optimizes the operation of its interconnected elements—from the central and distributed generator through the high-voltage transmission network and the distribution system, to industrial users and building automation systems, to energy storage installations, and to end-use consumers, and their thermostats, electric vehicles, appliances, and other household devices.

Current "smart grid" initiatives are driven by a number of potential benefits. The EPRI (2011a, p. 1-1) report correctly notes: "The present electric power delivery infrastructure was not designed to meet the needs of a restructured electricity marketplace, . . . or the increased use of renewable power production." The reference to a "restructured marketplace" emphasizes that a smarter grid can facilitate wholesale and retail competition in the supply of power, as well as the need to accelerate replacement of an aging transmission and distribution infrastructure and to conserve on meter reading and other network operating costs. The reference to renewable power points out that a smart grid may be needed if solar, wind, geothermal, and other renewable energy technologies are to make a sizable contribution to national electricity needs as well as engage with demand-side issues like charging electric vehicle batteries or encouraging consumers to use electricity more efficiently.

The American Recovery and Reinvestment Act of 2009 (ARRA) provided $4.5 billion in funds for smart grid demonstration and technology deployment projects, including various analyses of consumer behavior in response to the installation of "smart meters," discussed at ⟨http://www.smartgrid.gov/federal_initiatives⟩, a website sponsored by U.S. Department of Energy. About 140 projects have been funded under these programs with about $5.5 billon of matching funds from utilities and their customers. Several states have adopted regulations that require utilities to install smart meters and make other smart grid investments, while others have started more modestly with pilot programs. The costs of these efforts are typically recovered through regulated prices for physical distribution services. The federal funds have certainly accelerated activity on smart grid projects around the country, and these financial incentives have been reinforced by state mandates and pilot programs. Since it is unlikely that federal subsidies for smart grid investments will be sustained at their recent ARRA level, the performance of the projects supported with these funds and the experience with state mandates and pilot programs will be a powerful influence on whether and how fast smart grid investments continue in the future.

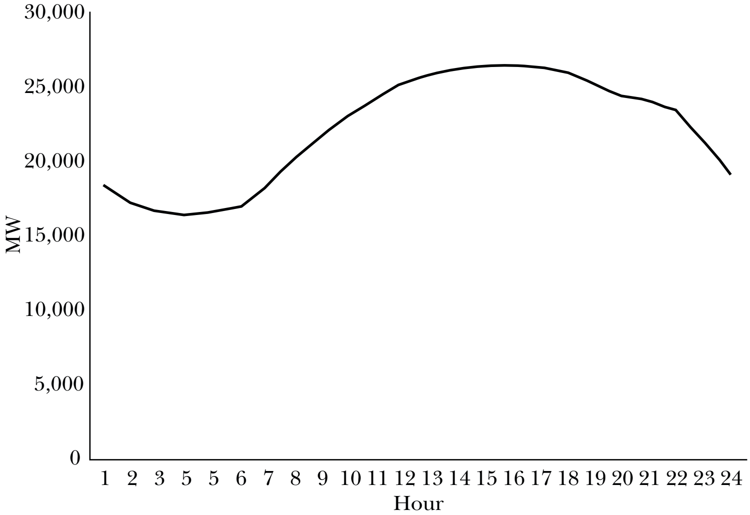
In what follows, I will examine the opportunities, challenges, and uncertainties associated with investments in "smart grid" technologies at each of the traditional components of the grid. I start by discussing some basic electricity supply and demand, pricing, and physical network attributes that are critical for understanding the opportunities and challenges associated with expanding deployment of smart grid technologies. I then discuss issues associated with the deployment of these technologies at the high voltage transmission, local distribution, and end-use metering levels. I will not discuss "behind the meter" technologies that may be installed inside of homes and businesses in response to the availability of smart grid capabilities, smart metering, and variable pricing.

Attributes of Electricity Markets

The demand for electricity varies widely from hour to hour, day to day, and month to month. Electricity demand is typically highest during the daytime hours and lowest at night. It tends to be very high on unusually hot or unusually cold days and is lowest at night on mild spring and fall days. Demand typically reaches its highest levels during only a few hours each year. There is also a minimum "base" aggregate demand that is sustained through the entire year. Figure 1 displays the levels of demand or "load" at different times of the day in New England on July 7, 2010. The peak demand is 60 percent higher than the lowest demand on that day. Figure 2 depicts the associated spot prices for electricity at each hour on that day, which I will discuss presently.

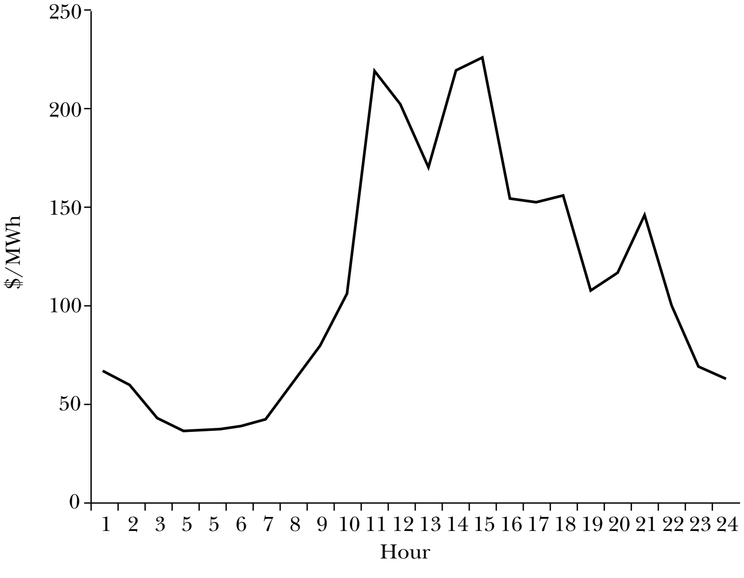
Electricity cannot be stored economically for most uses with current technologies (except in special applications where batteries, pumped storage, compressed air, and the like may be economically attractive). In electricity markets, physical

Figure 1
Real-Time Demand for Electricity, July 7, 2010
(in megawatts)



Source: Constructed from data from the New England ISO at ⟨http://www.iso-ne.com⟩.

Figure 2
Real-Time Energy Prices, July 7, 2010
(dollars per megawatt hour)



Source: Constructed from data from the New England ISO at ⟨http://www.ne-iso.com⟩.

inventories are not generally available to balance supply and demand in real time, and "stockouts" mean rolling blackouts or a larger uncontrolled system collapse (Joskow and Tirole 2007). On an electricity grid, supply and demand must be balanced continuously to maintain a variety of physical network criteria—like frequency, voltage, and capacity constraints—within narrow bounds. Electricity is the ultimate "just in time" manufacturing process, where supply must be produced to meet demand in real time.

These considerations have implications for the variations in the spot price of electricity in an unregulated wholesale electricity market and the shadow price of electricity in a traditional regulated environment that relies on an economic dispatch curve based on estimates of marginal generating costs. As demand increases, "dispatchable" generating capacity—first "base load," then "intermediate," then "peaking" capacity—with higher and higher marginal operating costs, is called to balance supply and demand (Turvey 1968; Boiteux 1964a; Joskow and Tirole 2007). As a result, wholesale market prices that reflect short-run marginal costs of generation are generally high when demand is high and low when demand is low, reflecting the marginal cost of the generation supplies needed to meet demand at different points in time. During unusually high-demand periods, supply and demand may (theoretically) be rationed on the demand side. When unexpected outages occur due to generation supply constraints or network failures, electricity consumers bear costs typically measured as the Value of Lost Load or VOLL (Stoft 2002; Joskow and Tirole 2007).

As noted, Figure 2 displays the variations in wholesale spot prices in New England associated with the variations in demand displayed in Figure 1 for a hot day in July 2010. The highest price is five times the lowest price on that day. More extreme price variability has been observed under more extreme weather conditions, though there is a \$1,000 per megawatt hour cap placed on spot prices for energy in most areas (\$3,000 in Texas).[1]

The prices in Figure 2 are *wholesale* spot prices. However, most *retail* residential and small commercial consumers are charged a retail price per kilowatt hour that does not vary dynamically with the time they consume electricity. As a result it does not reflect the wide variations in wholesale prices and the marginal cost of generating electricity. This is the case because traditional residential and small commercial users of electricity have meters that record only aggregate consumption between monthly or semi-monthly readings.[2] In some states, residential and small commercial consumers can opt for time-of-use meters, which charge different pre-set prices during predetermined "peak" and "off-peak" periods (for example, daytime and nighttime prices), based on averages of historical prices. While these

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[1] The price caps are generally thought to be well below the Value of Lost Load in most circumstances and this raises other issues for efficient short-run and long-run performance of competitive wholesale markets (Joskow 2005).

[2] In a few cases, the largest retail consumers were billed based on prices that did vary more or less with variations in wholesale market prices (Mitchell, Manning, and Acton 1978, pp. 9–16).

time-of-use retail prices somewhat more accurately reflect variations in marginal generation costs and wholesale market prices, the relationship between actual retail prices and actual wholesale prices is necessarily very rough indeed, and penetration of time-use retail pricing has been low.

Enhancing High Voltage Transmission Systems

High voltage transmission networks are central to the operation of a modern electric power system: they make it possible to meet locationally dispersed demand with locationally dispersed generation in an efficient and reliable manner. High voltage alternating current (AC) networks are not switched networks—like a traditional railroad or telephone network—that is, power generated at point A does not flow to a specific customer located at point B. Electricity flows on an AC power network according to physical laws known as Kirchoff's laws and Ohm's law (Clayton 2001; Stoft 2002; Hogan 1992; Joskow and Tirole 2000). To drastically oversimplify, electricity produced on an AC electric power network distributes itself to follow the paths of least resistance. Transmission networks can also become congested in multiple locations, which may not lie on the "path" between buyer B and seller A, as suppliers of relatively low-cost generation seek to use the network to sell power to areas with higher cost generation. Network congestion is reflected in differences in wholesale market prices for electricity (or in shadow prices where wholesale markets with locational pricing have not been created) at different locations on the network (Hogan 1992; Joskow and Tirole 2000).

Each of the three high voltage AC networks covering the continental United States experiences significant congestion during certain hours of the year, including many "off-peak" hours, although as far I know the costs of congestion have never been quantified systematically for the entire country.[3] A natural approach to measuring the magnitude and costs of congestion is to use the differences in locational wholesale prices over time. For example, Table 1 displays the average spot wholesale prices during peak hours at different locations on the Eastern Interconnection on that same day in July 2010. It should be clear that on July 7, 2010, power was not flowing from one location to another on the Eastern Interconnection to arbitrage away large differences in wholesale spot prices; the ability of the network to transfer power from one location to another was constrained by scarce transmission capacity.

This congestion and lack of wholesale locational price arbitrage arises for three primary reasons: First, the transactions costs for moving power from the North,

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[3] These costs, or at least the congestion rents, are quantified for the Regional Transmission Organizations (RTO) and Independent System Operators that have markets based on a locational marginal price market design. For example, in the PJM RTO, region, the independent market monitor estimated congestion costs to be as high as $2 billion in 2005, with substantial year-to-year variation, in his State of the Market Report for 2006 (PJM 2007, p. 39).

Table 1
Day-Ahead Peak Period Prices for Delivery July 7, 2010

Location	*$/MWh*
Boston (Massachusetts Hub)	117.75
New York City (Zone J)	138.50
Buffalo (Zone A)	79.00
Virginia (Dominion Hub)	107.75
Chicago (Illinois Hub)	68.75
Minneapolis (Minnesota Hub)	42.50
Florida	37.00

Source: Megawatt Daily, July 7, 2010, p. 2.

West, and South to New York City are high, requiring transactions with multiple Regional Transmission Organizations, Independent System Operators, and other balancing authorities with different market designs, settlement rules, and transmission service prices. Second, system operators place a very high value on reliability, which means maintaining "contingency" margins to be prepared for unanticipated events in neighboring areas which might affect their area. Third, most system operators have inadequate monitoring, communication, and control equipment on their high voltage network—an inadequate ability to "see" the state of neighboring networks—so they enforce higher contingency margins than would be necessary if they had better information and a wider span of control.

The benefit of these high contingency margins is that the U.S. electric transmission system is presently very reliable. While good comprehensive numbers are not available, it is extremely rare that retail consumers lose power because of failures of equipment or operating errors on the high voltage transmission system. EPRI (2011a, p. 2.1) estimates that U.S. power systems achieve 99.999 percent reliability at the high voltage (bulk) transmission network level and that over 90 percent of the outages experienced by retail customers are due to failures on the distribution system, not the transmission system (p. 6.1). However, when a rare major failure does occur on the high voltage transmission network, as with the 2003 Northeast Blackout when 50 million customers suffered power outages that lasted up to a couple of days, the associated costs can be high. (The 2003 Northeast Blackout was due in part to poor communications between system operators of interconnected control areas.)

It is widely accepted that there has been underinvestment in monitoring, communications, and control equipment on the high voltage transmission network to meet the needs of supporting efficient wholesale power markets, squeezing more effective capacity from existing transmission facilities, and achieving policy goals for renewable energy from grid-based wind and solar generating systems (for discussion, see EPRI, 2011a, chap. 5; New York ISO, ⟨http://www.nyiso.com/public/energy_future/issues_trends/smart_grid/index.jsp⟩; U.S. Department of Energy ⟨http://www.oe.energy.gov/⟩). EPRI (2011a, p. 5.1) recognizes that while it is hard to estimate with precison the costs of upgrading the high voltage transmission system with this "smart" equipment, EPRI estimates that the total investment cost is \$56–\$64 billion. EPRI also concludes the investments in improved monitoring of high voltage transmission networks represent the most cost-effective category of smart grid investments. Investments in this category also represent about 20 percent of the total cost of EPRI's defined Smart Grid program. This is qualitatively consistent with my own assessment.

These smart grid investments at the high voltage transmission level are likely to have even higher returns as "intermittent" generating capacity like high voltage grid-connected wind and solar generating capacity grows (local photovoltaic facilities on the roofs of homes create related challenges for distribution networks—see below). High voltage grid-based wind and solar installations supply electricity intermittently. This means that their output is driven by wind speed, wind direction, cloud cover, haze, and other weather characteristics rather than by supply and demand conditions and wholesale market prices. As a result, their output typically cannot be controlled or economically dispatched by system operators based on economic criteria in the same way as traditional electricity generation technologies (Joskow 2011a, b). Since wind and sun intensity vary widely and quickly, output of intermittent generating units can vary widely from day to day, hour to hour, minute to minute, and location to location. To balance supply and demand continuously when there is significant intermittent generation on the high voltage network requires that system operators have the capability to respond very quickly to rapid changes in power flows at different locations on the network by holding more dispatchable generation in operating reserve status and having the capability to monitor and adjust the configuration of power flows on the transmission network to balance supply and demand continuously while minimizing costs.[4]

Smart grid investment on the high voltage network has only a limited ability to increase the effective capacity of transmission networks. A large increase in transmission capacity, especially if it involves accessing generating capacity at new locations remote from load centers, requires building new physical transmission capacity. However, building major new transmission lines is extremely difficult. The U.S. transmission system was not built to facilitate large movements between interconnected control areas or over long distances; rather, it was built to balance supply and demand reliably within individual utility (or holding company) service areas. While the capacity of interconnections have expanded over time, the bulk of the price differences in Table 1 are due to the fact that there is insufficient transmission capacity to move large amounts of power from, for example, Chicago to New York City. The regulatory process that determines how high voltage transmission capacity (and smart grid investments in the transmission network) is sited and paid

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[4] These network issues associated with intermittent generating capacity are different from issues related to the proper comparative valuation of intermittent and dispatchable generating technologies (Joskow 2011a, b); Borenstein (2008) applies methods compatible with those in Joskow (2011a, b) to derive the cost per kilowatt hour supplied and the cost per ton of CO_2 displaced by substituting solar for fossil-fuel generation expected to result from California's rooftop solar energy subsidy program.

for in regulated transmission prices is of byzantine complexity (Joskow 2005). It is clear, however, that the combination of FERC cost allocation policies, the requirement to receive siting permits from each state in which a new transmission line is located, and not-in-my-backyard political constraints hinder efficient investment in long distance transmission lines. FERC has been trying to resolve the issue of "who pays" and "how much" for new transmission lines for years, most recently promulgating Order 1000 in July 2011. This rule has many constructive features, but it will take several years to see how and to what extent it is implemented. Nor does that rule address state siting requirements or NIMBY constraints. Congress gave the Department of Energy authority to designate National Interest Electric Transmission Corridors to respond to the diffusion of siting authority among many states, but the DOE's procedures have been rejected by the courts (Watkiss 2011). The best solution to the siting problems would be to move regional transmission planning authority from the states to FERC. However, the political barriers to such a change are enormous. Thus, underinvestment in multistate high voltage transmission facilities is likely to continue to be a problem for many years.

Automating Local Distribution Networks

The smart grid technologies being deployed on local distribution systems include enhanced remote monitoring and data acquisition of feeder loads, voltage, and disturbances; automatic switches and breakers; enhanced communications with "smart" distribution substations, transformers, and protective devices; and supporting communications infrastructure and information processing systems. Smart grid investments in local distribution networks offer a variety of potential gains: to reduce operation and maintenance costs (goodbye meter readers, manual disconnects, and responses to nonexistent network outages); to improve reliability and responses to outages; to improve power quality (for example, to eliminate very short disruptions in voltage or frequency); to integrate distributed renewable energy sources, especially solar photovoltaic systems installed at customer locations that produce power intermittently and can lead to rapid and wide variations in the (net) demand placed on the distribution network; to accommodate demands for recharging of the electric vehicle of the future; to deploy "smart meters" that can measure customers' real-time consumption and allow for dynamic pricing that reflects wholesale prices; and to expand the range of products that competing retail suppliers of electricity can offer to customers in those states that have adopted retail competition models.

The U.S. Department of Energy has supported about 70 smart grid projects involving local distribution systems on a roughly 50/50 cost sharing basis, with details available at ⟨http://www.smartgrid.gov/recovery_act/tracking_deployment/distribution⟩. However, a full transformation of local distribution systems will take many years and a lot of capital investment. Are the benefits likely to exceed the costs?

In the only comprehensive and publicly available effort at cost–benefit analysis in this area, the Electric Power Research Institute (2011a) estimates that deployment (to about 55 percent of distribution feeders) would cost between \$120–\$170 billion, and claims that the benefits in terms of greater reliability of the electricity supply would be about \$600 billion (both in net present value).[5] Unfortunately, I found the benefit analyses to be speculative and impossible to reproduce given the information made available in EPRI's report.

According to EPRI (2011a, page 6.1), over 90 percent of the electricity supply outages experienced by retail electricity consumers occur because of failures on the local distribution network rather than the transmission network. These failures may be caused by wind and storms, tree limbs falling on overhead distribution lines, icing up of distribution equipment, overloads of the local distribution network, failures of low-voltage transformers and breakers due to age or poor maintenance, cars that crash into poles and knock down distribution equipment, flooding of underground distribution, excessive heat, natural aging, and so on. No matter how smart we make local distribution systems, power outages will arise from many of the natural causes on this list, especially in areas that rely on overhead (rather than underground) distribution lines. Using standard measurement criteria from the IEEE (Institute of Electrical and Electronics Engineers), which exclude certain planned and weather-related outages, the average residential household has (rounding to simplify the calculation) 1.5 unplanned outages per year with an average outage duration of about 100 minutes per year (Power Engineering Society, 2006). Accordingly, the average residential customer experiences about 150 minutes of unexpected outages per year or 10.5 percent of one day per year. When I compare EPRI's estimates of the benefits from greater reliability with typical estimates of Value of Lost Load—for example, \$5,000 to \$10,000 per megawatt hour lost—the EPRI estimates of reliability benefits appear much too high.

Very short voltage drops and electrical transients that appear almost as flickers of lights (poor "power quality")—potentially create significant problems for very sensitive digital equipment. Investments in smart distribution grid technology can reduce these transients, but at significant cost. The value of reducing these transients also varies widely among customers. Having to reset one's clock is less costly than maintaining backup facilities for a critical server or data storage system in the event of disruption or damage from a voltage spike, as a financial management firm might have to do. In crafting a response, we must address the question of whether investments to improve power quality should be made for everyone, or whether they should be made "behind the meter" by those who value power quality highly? This issue would benefit from more independent empirical evidence and analysis.

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[5] More specifically, nearly half of the overall benefits (\$445 billion in net present value) for EPRI's (2011a) entire smart grid program are attributed to "reliability," which appears to be shorthand for reliability and power quality. There is another benefit category called "security" (benefits of \$151 billion in net present value), which seems to be a subset of "reliability." Adding these gives the total of roughly \$600 billion in the text.

Of more pressing concern are the new demands that may be placed on at least some distribution systems by distributed generation, primarily solar photovoltaic systems, and by the potential future need to recharge plug-in electric vehicle batteries. Several states are promoting solar photovoltaic technology with large subsidies (Borenstein 2008). Due to the wide variability in the output of photovoltaic technologies, sometimes over short time periods (NERC 2009, pp. 27–29), and related variability of net demand (which could be net *supply* if there are enough photovoltaic facilities and it is very sunny) that consumers place on the distribution system, photovoltaic technologies will place new stresses on local distribution feeders where they are installed. Better remote real-time monitoring and remote and automatic control capabilities, data acquisition and analysis of the state of the distribution system, and automatic breakers and switches will be required to accommodate significant quantities of these resources efficiently and safely.

The rate of new photovoltaic installations will vary widely from distribution feeder to distribution feeder and from state to state because of differences in subsidy policies and the relative economic attractiveness of photovoltaic investments. This variation suggests a targeted approach to local distribution system automation: focus first on areas where distributed generation, and the related stress on specific distribution feeders, will happen sooner.

The potential future demands placed on the local electric distribution system by plug-in electric vehicles raise similar issues. In 2010, out of 11.6 million total car sales, there were at most 3,000 pure electric plug-in electric vehicles sold and about 275,000 plug-in hybrids. The future path of electric vehicle sales depends on many factors: the price of gasoline, subsidies for electric vehicles, technological change affecting battery life and costs, new emissions standards, reductions in electric vehicle costs, and consumer behavior. Forecasts of the fraction of new vehicles that will be electric plug-ins by 2035 varies from less than 10 percent to over 80 percent. The U.S. Energy Information Administration (EIA 2011a, p.72; see also EPRI 2011b, chap. 4) forecasts a market share of light-duty vehicles of only 5 percent for plug-in and all-electric vehicles in 2035 in its reference case. The National Research Council (Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies, 2010, p. 2) concludes that a realistic estimate is that by 2030 about 4.5 percent of the national light duty vehicle fleet will be plug-in electrics—with a maximum possibility of about 13 percent.

Along with the number of plug-in cars, the load placed on the distribution system will depend on the attributes of the car batteries and charge-up time selected by vehicle owners. Shorter charging times at higher voltages can place very significant loads on local distribution networks even with modest electric vehicle penetration (Browermaster 2011). An interesting possibility arises here. The demand on portions of the *local distribution system* in areas where electric vehicle sales may be concentrated—say, in places like Berkeley, California or Cambridge, Massachusetts—could peak at night, even when prices in the much broader wholesale power market are low. The possibility that the marginal cost of electricity distribution service on some distribution feeders could peak at times when aggregate system demand for power and associated power prices in the wholesale market are low suggests that more thought should be given to altering the pricing of electricity distribution service. Distribution service prices are now based on a flat per kilowatt hour rate and do not vary with the marginal costs of distribution service, which is driven largely by the peak demand on distribution feeders. Distribution service prices would more closely reflect the associated marginal cost of this service if we moved, instead, to a distribution charge based at least partially on individual customers' peak load on the local distribution system.

These considerations all lead to the conclusion that phasing in the installation of smart grid technology, targeting investment where it is likely to be most needed quickly, and collecting data using a controlled experimental framework to evaluate its costs and benefits would be a sensible strategy.

I offer one caveat to this conclusion. Many U.S. distribution systems are aging, and utilities are embarking on large distribution network replacement programs. These investments are long-lived, and it makes sense for these programs to take advantage of the most economical modern distribution technologies. In many cases, forward-looking investment optimally should deploy much more automation and communication technologies than immediately needed, even if deployment of distributed generation and electric vehicles is expected to be slow.

Smart Meters and Dynamic Pricing Incentives

It is not unusual for the incremental generating capacity held by a utility or RTO to meet the peak demand on its system during the 100 highest demand hours each year (1.1 percent of the total hours) to account for 10 to 15 percent of the generating capacity on its system. This is the direct consequence of the wide variability of demand (especially in response to extreme weather conditions), the failure of retail prices to reflect the true marginal cost of supply under these extreme conditions, and the utility practice of building enough generating capacity to meet demand even under very extreme low-probability demand states. Accordingly, using appropriate prices to provide consumers with an incentive to cut peak demand during a small number of hours can reduce generating costs significantly in the long run. Retail prices that are not tied to variations in wholesale prices inefficiently increase the level of peak demand by underpricing it, and may also discourage increased demand during off-peak hours by overpricing it.

The idea of moving from time-invariant electricity prices to "peak-load" pricing where prices are more closely tied to variations in marginal cost has been around for at least 50 years (Boiteux 1964b, c; Turvey 1968; Steiner 1957; Kahn 1970, pp. 63–123). The application of the theory in practice has lagged far behind, especially in the United States. (Mitchel, Manning, and Acton (1978) discuss early developments in other countries.) There is evidence from the well-designed experiments with time-of-use pricing of electricity in the 1970s showing consumers do respond more or less as expected to price incentives (Aigner 1985), in the sense that higher prices lead to less consumption. The magnitude of the estimated responses varies widely though and does not reflect potential adaptations in the attributes of the appliance stock resulting from widespread deployment. Moreover, a 2010 survey indicated that only about 1 percent of residential customers were on time-of-use rates (FERC 2011, pp. 28, 99).

"Smart meters" can record *real-time* consumption of electricity. They also can have two-way communications capabilities allowing for real-time retail prices tied to variations in wholesale prices (and a number of variations on this theme), and could lead to remote control of customer demand by allowing the retail supplier or the customer to adjust appliance utilization inside the customer's home or business. For example, a customer might program the air conditioning (or have the utility program it) to turn off, at least intermittently, when electricity prices reach a certain level. Real-time pricing to reflect variations in wholesale market prices can increase efficiency, at least when it is applied to larger customers (Borenstein 2005). In addition, real-time pricing can stimulate innovations in appliances and equipment inside the home or in business to make them capable of responding more easily to changes in real-time prices and load management arrangements made with retail suppliers.

The traditional arguments for not introducing real-time pricing were: 1) the meters and billing costs would be so costly that residential and small commercial customers would not benefit from them; 2) retail consumers would not understand or effectively utilize complex rate designs; and 3) changing rate designs would lead to large redistributions of income reflecting the wide variations in consumption patterns across individuals and decades-old mechanisms for allocating costs among types of customers and within customer classes (Borenstein 2007a, b).

At least some of these arguments are increasingly being questioned, and solutions being contemplated. Metering and communications technology have moved forward with more capabilities and lower costs. Today's more advanced smart meters use two-way communication and capabilities for active real-time interaction between the distribution system and the customer: they can record consumption at least once each hour, can be turned on and off remotely, can support the introduction of dynamic retail prices that are closely tied to dynamic wholesale market prices, and can control the utilization of appliances remotely in a way that facilitates active demand-side management of the electrical grid. In addition, the information available through smart meters can inform the distribution company about variations in demand and equipment outages on the distribution grid instantly, thus creating synergies between "smart meters" and smart distribution grid investments. Variations on full real-time pricing, in particular "critical peak pricing," are easier for consumers to understand and provide much better incentives than flat rates. Nevertheless, relatively few advanced "smart meters" had been installed and used effectively in the United States, although the number is now increasing at a rapid rate (U.S. Energy Information Administration 2011b) as a result of federal subsidies and state mandates. As many as 8.7 million smart meters have now been installed at residential and small commercial locations, about 6 percent of the total—though the definition of what counts as a smart meter varies and experience with them is limited (St. John 2009).

Analysis of the costs and benefits of large-scale deployment of smart meters must look at both changes in consumer surplus and changes in the cost of supplying electricity and metering its consumption. On the demand side, one needs to be able to measure the demand elasticities and cross-elasticities for a very diverse population of consumers who have different appliance stocks, live in homes of widely varying sizes, experience different weather conditions, face different levels and structures of incumbent electricity tariffs, have different incomes, and consume different quantities of electricity each month. An added complexity is that it would be implausible to measure *long-run* demand elasticities taking the current attributes of appliances and equipment as given, because the appliance stock and opportunities to adjust energy use will change to take advantage of the new incentives if smart meters and dynamic pricing are widely used.

On the supply side, there are questions about how much all of this whizzy smart grid technology will cost and, as always, there is the need to measure the effects on generation, distribution, and transmission costs. Measuring incremental metering costs is not easy. The many different vendors of smart meters sell meters with different functionalities and different communications methods. Moreover, buying and installing the meters is only part of the cost: communications systems must be built to integrate smart meter information with automated distribution network capabilities; a new information technology infrastructure for data acquisition, analysis, and billing created and installed; customer service personnel retrained to respond to questions about more complex rate structures; and investments made in complementary distribution system upgrades. On the other hand, smart meters should also save operating costs, primarily by reducing meter-reading costs (especially for systems that have not already installed the first-generation one-way communication meters). We also know that as a theoretical matter, setting retail prices to reflect marginal supply costs will increase overall efficiency with which electricity is consumed and supplied. But is this efficiency gain large enough to cover the additional costs of smart meters and associated information and automated distribution technology, both in the aggregate and for customers with different utilization characteristics? I do not think that this question has yet been answered satisfactorily or the public adequately convinced that the answer is likely to be affirmative.

A large number of U.S. utilities began offering time-of-use and interruptible pricing options for large commercial and industrial customers during the 1980s, either as a pilot program or as an option (for example, Barbose, Goldman, Bharvirkar, Hopper, Ting, and Neenan 2005). More recently, a number of states have introduced pilot programs for residential (household) consumers that install smart meters of various kinds, charge prices that vary with wholesale prices, and observe demand. For example, Taylor, Schwarz, and Cochell (2005) estimate hourly own- and cross-price elasticities for industrial customers on Duke Power's optional real-time rates and find large net benefits for these customers. Faruqui and Sergici (2010) summarize the results of 15 earlier studies of various forms of dynamic pricing, including time-of-use pricing, peak pricing, and real-time pricing. Faruqui and Sergici (2011) analyze the results of a dynamic pricing study performed by Baltimore Gas & Electric using treatment and control groups drawn from a representative group of households. Wolak (2006) analyzes a peak pricing experiment in Anaheim, California. Wolak (2010) analyzes a pilot program using peak pricing in Washington, D.C. Allcott (2011) analyzes data from the Chicago Energy Smart Pricing Plan that began operating in 2003. Faruqui (2011) summarizes the reduction in peak load from 109 dynamic pricing studies, including those that use time-of-use pricing, peak pricing, and full real-time pricing, and finds that higher peak period prices always lead to a reduction in peak demand. However, the reported price responses across these studies vary by an order of magnitude, and the factors that lead to the variability of responses have been subject to very limited analysis.

Before discussing what conclusions can be drawn from this evidence, a few warnings seem appropriate. First, there is wide variation in the design of the pilot/experimental studies and the variation in prices included in them. Just looking at the magnitude of the response without more information is not adequately informative. Second, essentially all of these studies include only "volunteers," which raises the possibility that those who choose to participate may be unusually sensitive to price variation. Third, many of these pilots include a very small number of participants, and in at least one study a large fraction of those who started in the pilot dropped out before it was completed. Fourth, few of the pilot programs use full real-time pricing. A few use "critical peak pricing" mechanisms, and this may yield results similar to what we would get with full real-time pricing. For example, PG&E's voluntary tariff for customers with smart meters starts with the regular tariff price, except during "Smart High Price Periods," which are communicated to the customer in advance by telephone, Internet posting, or text messaging, and the price rises to 60 cents per kilowatt hour between 2 p.m. and 7 p.m. for a maximum of 15 days per summer season. Fifth, several of the pilots apply only one price to the treatment group, which makes it impossible to trace out the relevant demand functions without making very strong assumptions about the shape of the demand curves. Using several treatment groups requires a larger pilot study than has often been the case (see Aigner, 1985, regarding the need for multiple treatment groups). Finally, few of these studies use data on consumer responses along with electricity supply and metering cost data to perform a proper cost–benefit analysis. Indeed, I have not yet seen a recent study as well designed, or with a welfare analysis as carefully performed, as the Los Angeles experiments managed and analyzed by RAND during the 1970s (Mitchell and Acton 1980).

Despite these concerns, the available evidence does suggest a number of conclusions: First, consumers do respond to higher peak prices by reducing peak demand. Second, dynamic pricing with very high prices during critical periods generally leads to much larger prices responses than traditional time-of-use pricing with predetermined time periods and prices, which typically use much smaller price differences. Third, wide variation in price responsiveness is observed across studies, suggesting wide underlying variation in the attributes of households and pilot study conditions. Fourth, most if not all of the price response to higher peak period prices is to reduce peak demand rather than to shift from peak to off-peak demand. For example, a common reaction is to use less lighting, air conditioning, and refrigeration when prices are high—with no offsetting increase in electricity used at other times. However, the diffusion of plug-in vehicles or other technologies where time-of-use is a more important choice variable could yield very different results.[6] Fifth, technologies and information that make it easier for consumers to respond to high price signals lead to larger responses to any given price increase, although many of the reported results do not contain adequate information to estimate demand functions or to perform proper cost–benefit analyses.

Faruqui and Wood (2011) present a well-conceived "template" for what items should be included in a comprehensive cost–benefit analysis and present simulations for four "prototype" utilities. The aggregate benefit/cost ratios vary from 1.4 to 1.9 for the four simulations. The simulations are not based on real utilities nor complete data, but the hypothetical numbers are not unreasonable and the results are suggestive. Of course, cost–benefit analysis of universal smart meter installation and real-time pricing may also find that while the benefit/cost ratio is greater than 1.0 in the aggregate, it may not be beneficial to some significant number of individual customers. Borenstein (2007b) takes the wide variation in customer utilization attributes seriously, although his focus is on larger commercial and industrial customers, not residential customers. But the heterogeneity of the effects of smart meters and real-time pricing on residential and small commercial customers is an important issue that still needs to be addressed.

Some states that have mandated the installation of smart meters for all customers have found the decision to be controversial (for newspaper accounts, see Smith, 2009; Turkel, 2011a, b; Fehrenbacher, 2010; Baker, 2010). Some consumers have reacted negatively to increases in up-front distribution costs to pay for the smart grid enhancements. First, some customers with "unfavorable" consumption patterns—weighted toward times when prices are high—may see higher bills, rather than the lower bills they are being promised, compared to their billing under flat rates (Borenstein 2007b). Second, some smart meters have been deployed too quickly and have not worked properly. Third, with all of the data that these meters can collect, privacy advocates have raised concerns about

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[6] "Storage space heating" allows off-peak electricity to be used to heat up special bricks or slabs or water tanks, which are then used as a source of warmth during on-peak hours. When storage space heating was introduced in Europe during the 1960s, it was consciously designed to shift demand to off-peak periods. It did such a good job that the peak shifted from day to night in England and northern Germany and the regulated prices no longer reflected the patterns of demand and cost. Steiner (1957) and Kahn (1970) discuss this "shifting peak" case theoretically. More generally, we should be reminded that we should not take our eyes off of the long-run equilibrium which may look very different from the short-run equilibrium—especially after technological change.

what data will be made widely available and how it may be used and protected. Finally, some public utility commissions and some utilities have done a poor job educating their customers and have rolled out their smart meter installation program too quickly. There are lessons to be learned about deployment strategy from these experiences.

Conclusions

The existing electricity distribution system is very old in many areas, and investments to replace key components will have to accelerate just to maintain the reliability of the system. These replacement programs should be consistent with longer-term strategies for modernizing the distribution system. However, there is a lot of uncertainty about the size of costs and benefits, and these costs and benefits vary across distribution feeders as well as customers and regions. The rate and direction of future technological change on both sides of the meter is also uncertain. The transition to smart grid technology is going to take years, and there are sure to be notable bumps along the way.

Accordingly, it seems to me that a sensible deployment strategy is to combine a long-run plan for rolling out smart-grid investments with well-designed pilots and experiments. Using randomized trials of smart grid technology and pricing, with a robust set of treatments and the "rest of the distribution grid" as the control, would allow much more confidence in estimates of demand response, meter and grid costs, reliability and power quality benefits, and other key outcomes. For example, Faruqui's (2011b) report on the peak-period price responses for 109 pilot programs displays responses between 5 to 50 percent of peak demand. An order-of-magnitude difference in measured price responses is just not good enough to do convincing cost–benefit analyses, especially with the other issues noted above. In turn, the information that emerges from these studies could be used to make mid-course corrections in the deployment strategy. Given the large investments contemplated in smart meters and complementary investments, along with the diverse uncertainties that we now face, rushing to deploy a particular set of technologies as quickly as possible is in my view a mistake.

Despite these reservations, the country is on a path to creating smarter transmission and distribution grids. Exactly how far and how fast we go remains quite uncertain, especially as the federal subsidies enacted in 2009 for promoting the smart grid come to an end.

■ *The views expressed here are my own and do not reflect the views of the Alfred P. Sloan Foundation, MIT, Exelon Corporation, Transcanada Corporation, or any other organization with which I am affiliated. I am an outside director of Exelon Corporation and of Transcanada Corporation. My other affiliations are identified on my CV at ⟨http://econ-www.mit.edu/faculty/pjoskow/cv⟩.*

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PROMOTING INNOVATION IN THE ELECTRICITY INDUSTRY[1]

L. Lynne Kiesling

Smart metering can bring significant benefits to the electricity markets by allowing customers to reduce demand or increase supply when generation capacity is temporarily scarce. To reap the full efficiency and environmental benefits of this technology, regulators must allow price volatility and free entry into the market. The efficiency gains are enormous as both demand and supply will be affected by both temporary and longer-lasting price changes. Experiments have shown the value of this approach.

Keywords: Utility regulation, electricity markets, smart metering.

Technology and institutional design

How does technological change affect the role of economic regulation in retail electricity markets? I will offer some observations and research from a US perspective that I believe generalise to other settings as well. I also hope to challenge some current thinking about the potential retail value propositions involving electricity, and the role of regulation in retail markets in the presence of technological change. In particular, digital communication technology has made rich, vibrant, customer-oriented innovation possible. Some examples of such consumer-focused innovation include appliances and devices that can respond autonomously to changes in electricity prices; electric vehicles that can be programmed to charge when electricity prices fall below a trigger price set by the owner and serve as an energy storage device as well as a vehicle; or home energy management systems that enable the homeowner to set appliances to power down if the electricity they are using would be bought on the wholesale market during an hour when renewable power was not available (the green–grey portfolio mix). The technologies to bring these products and services to retail customers exist: the regulatory institutions that enable it do not.

These topics fall under the general category of smart grid. The buzz around the idea of smart grid is palpable: old companies such as General Electric and new companies such as Google are changing their business models to incorporate more smart grid activities and products, entrepreneurs are exploring new products and services at unprecedented rates, and federal legislation supports smart grid investments and has directed $40 billion of taxpayer funding to smart grid investments.

Defining ‘smart grid’ requires thinking about the subject from two different directions simultaneously – its technologies and its functionalities. Technologically, a smart grid is a digital communication overlay and integration into the electric power network. This communication technology includes:

- digital switching networks;
- remote sensing and monitoring in wires and in transformers;
- fault detection in wires and in transformers;
- devices for automated fault repair; and
- intelligent end-use devices in homes, stores, office buildings, garages and factories.

These various smart grid technologies enable a variety of functionalities in the electric power network, such as:

- transactive co-ordination of the system (many of the following functionalities contribute to this co-ordination);
- distributed resource interconnection, including renewable generation and electric vehicles;
- the ability of a resource/agent to be either a producer or consumer of electricity, or both;

- demand response to dynamic pricing, and automation of that response;
- the ability of an agent to program end-use devices to respond autonomously to price signals; and
- distribution system automation by the wires company, leading to better service reliability.

The integration of these technologies into the electric power network will embed distributed intelligence in the physical systems that the network comprises. When I refer to the grid or the electric power network I am including distributed human agents (and their private knowledge–preferences–intelligence) in the definition of the network, not just the physical assets.

The potential ways that smart grid capabilities can create value are large, and they transcend the traditional utility-provided, generic electricity generation and delivery value proposition. By enabling better, and more decentralised, co-ordination of electricity supply and demand, smart grid functionalities contribute to the optimisation of resource use in the entire electricity system. This optimisation has both economic (cost reduction) and environmental (reduced resource use, reduced emissions) implications. Note, though, that the connection between distributed intelligence and decentralised co-ordination allows these economic and environmental benefits to align and converge. One example of this convergence is how dynamic retail pricing induces consumers to shift consumption away from expensive peak hours, which leads to a reduced need for expensive infrastructure investment that is built to meet peaks and then sits idle for 95% of the year: avoiding that investment saves costs and saves resources.

Paradigm shift

These dramatic and exciting technological changes are on the verge of creating a paradigm shift in this industry. Historically vertically integrated and regulated, the electric power industry in the USA was designed for centralised physical and economic control, both for operational reasons and for economic efficiency and equity reasons. Reliability and system balance have always been the paramount policy objective, and from an economic perspective, the principal illuminating regulation has been a concept of ‘the public interest’ used to control the exercise of market power. Under the public interest theory of regulation, creating monopoly electric utilities and regulating the rates of return they earned minimised the deadweight loss associated with monopoly, while at the same time eliminating the competition that drove market prices below long-run average cost under free entry. This argument is based on neoclassical natural monopoly theory, in which the cost structure of the firms in the industry relative to the size of the market would ultimately lead to having a single firm operate in that market.

These regulatory and legal concepts are generally static, and do not adapt well to unforeseen and changing conditions, including economic dynamism and technological change. Consumer-focused, end-use innovation creates the opportunity to access consumer intelligence at the edge of the electric power network, enabling distributed, individual agents to co-ordinate their plans and actions transactively. Through that process we achieve what is known in complexity science as emergent order through decentralised co-ordination. However, regulatory institutions that are designed for centralised control, and the economic interests of incumbents who profit from that state of affairs, present barriers to achieving this decentralised co-ordination.

Moreover, regulatory policy objectives in electricity are increasingly in tension. Reliability of service and of the physical network is paramount, and rightly so. Another high-priority objective for the past century has been affordability and predictability, in the form of low, stable retail prices that insure all retail customers against price volatility. Intended as a bulwark against monopoly, this policy also stifles both the communication of cost information to consumers and the communication of consumer preferences back all the way through the value chain to generators. Consequently, to the extent that consumer preferences and production costs vary from average benefit and average cost over time, these regulated, averaged prices lead to inefficient outcomes with distorted resource allocation.[2]

Over the past 20 years, though, the complexity of our policy objectives has increased as our interest has grown in reducing the environmental impacts of energy use, and in decreasing energy use and improving energy efficiency. Low, fixed (and still regulated in most of the USA) retail prices are in direct tension with consumer empowerment to reduce the environmental impacts of energy use. Fixed, averaged, regulated retail prices send no signal, and give no incentive, about the relative economic or environmental value of changing consumption at a particular time. The current context of increasing capital costs and supply constraints compounds that tension.

These observations prompt the question: are low, stable retail prices that do not reflect underlying cost fluctuations actually in the public interest, particularly in light of innovations in end-use digital technology? Is our historical policy focus on low, stable prices still serving the public interest?

A different way to frame this question is to note that technological innovation and institutional design are symbiotic, and that when regulatory institutions do not evolve along with technology they can become maladaptive and counterproductive to our broader social goals of economic efficiency and equality of opportunity. The interaction between technological change and retail regulatory and market design is substantial, and can either be positive or negative for consumers, for entrepreneurs, and for incumbents.

The GridWise Olympic Peninsula case study

The GridWise Olympic Peninsula project is a concrete research project that illustrates these ideas. The Olympic Peninsula is located in Washington, in the northwest corner of the USA, and residents in this area use electricity primarily for winter heating. Population growth in the area has created a constrained electricity distribution network, with expectations of further future constraints. The traditional regulated utility response to demand growth is, naturally, to increase capital investment in generation and wires capacity, because under rate-of-return regulation the firm's profits are a function of its 'rate base', its capital stock. Two challenges to this traditional response presented themselves – population and demand are growing because people move to the Olympic Peninsula for its natural beauty, and do not want it despoiled by more generating and distribution capacity, and the physical terrain of the area would make such infrastructure construction extremely costly. Thus, the proposal came from researchers at the Pacific Northwest National Laboratory to look at digital end-use technology and retail pricing as ways to increase capacity utilisation with the existing network assets.[3]

Homeowners participating in this project received a transactive, price-responsive communicating thermostat and water heater, and they could choose from among three different retail contracts:

- *Fixed price:* the price per kilowatt-hour did not change over time, and reflected the insurance premium for the insurance that the consumer received against price volatility;
- *Time of use (TOU):* this peak/off-peak price structure included a higher price in peak hours (6am–9am and 6pm–9pm) and a lower price during all other hours; and
- *Real-time price (RTP):* the energy portion of the consumer's price fluctuated to reflect real-time changes in the wholesale electricity price (as approximated in this project by the Dow Jones Mid-Columbia wholesale price). This price could change as often as every five minutes.

They also had in-home visual displays that made changing settings easy – if you can programme a digital video recorder you can control your own electricity use according to your preferences using this technology. The experiment also included a control group with technology that did not participate in the retail choice treatment.

The most novel institutional design innovation in the project was the design of a double auction for the RTP contract customers. A double-auction market design has active buyers and sellers simultaneously submitting bids and offers, which creates an information-rich environment that converges to equilibrium more quickly than other market designs. In this double-auction retail market, the household's transactive appliances submitted bids, while suppliers submitted offers to supply. This market cleared every five minutes for a year, and is the first use of a retail, real-time double-auction market.

In brief, the results of this year-long project were customer savings, increased distribution capacity utilisation and high reliability. On average, customers saved 10% on their bills, peak demand fell by 15% and overall electricity consumption fell, resulting in multiple types of conservation.

The RTP customers saved the most money, and the TOU customers reduced their consumption the most. This project provides just one example of how retail choice and product differentiation can be welfare-enhancing for individual consumers and also achieve system-related policy objectives. Other test beds and projects in the USA are finding corroborating results, although none has yet implemented a real-time double-auction retail market design (but some are working towards it).

Note also that extrapolating the results of this project nationally would suggest substantial avoided investment over 20 years. This avoided investment would mean lower production costs (other things equal) and long-term environmental benefits due to reduced resources being used to meet electricity demand.

This project is a concrete example of my main points:

- The symbiosis of technology and institutions is crucial for achieving the greatest potential value for electricity consumers from technological change (transactive technology + portfolio of retail products).
- Technology and market design can combine to transform a complex system into a complex *adaptive* system, harnessing edge intelligence to create economic and environmental value by empowering residential retail consumers to control and manage their own electricity consumption decisions and use technology to automate their responses to dynamic prices.
- Technology and market design can lead to emergent order through decentralised co-ordination rather than the hierarchical physical and economic control on which this industry has relied for the past century.

Consumer-focused smart grid innovation

Digital communication capabilities in the network, including in end-use devices, provide increasingly feature-rich, mobile ways to create consumer awareness about electricity consumption, electricity expenditure and the environmental impact of that consumption. They also provide ways to change electricity consumption, either manually or automatically, in the home or remotely. For example, a home can have a home area network (HAN) that connects its appliances, its heating and cooling, its water heater, its laundry, its entertainment (stereo, TV, DVR, game console) and its lighting into one communication network, accessible either through a computer screen in the home or a web-based portal that can be accessed via a computer or a web-enabled mobile device. Through this communication interface, the customer's electricity retailer can communicate real-time information about the quantity of electricity consumed, the price the consumer is paying, and even the type of generation resources being used to generate the power being consumed. The retailer can also communicate price signals to the customer, and the customer can program the different devices in the HAN to change their settings in response to price changes – e.g. if the price increases from nine cents to 12 cents, reduce the temperature in the water heater by five degrees, and increase the thermostat air conditioner setting by five degrees. Moreover, the consumer can have remote web access to the HAN, and can change settings, monitor energy consumption and analyse data on the home's electricity consumption.

Say, for example, you are on the train to work and you get an SMS notification that due to unexpected weather, there will be a higher-than-normal electricity price between 9am and 10am. You may have already programmed your devices to respond to price signals, but what if the price is high enough that you want to change your settings? You can log in to your

HAN from your mobile device, or from your computer at work, and change the device settings in the home through the web portal.

Such functionality requires intelligent end-use devices, which are increasingly feasible and cost-effective as the costs of information technology fall. Intelligent devices include thermostat, water heater, television and so on that have digital communication capability. Intelligent devices can have their settings changed remotely and can be programmed to respond to data, including price signals.

Furthermore, if the home has distributed generation installed, such as solar photovoltaic rooftop panels, the customer can program the network to reduce electricity use once the home's consumption reaches the generation capacity of the solar resource, thereby reducing the use of energy overall and reducing the use of fossil-fuel-generated power if the marginal generation resource at that time is coal or natural gas (of course, with retail choice, the customer could choose a 100% renewable energy contract if desired, which would alleviate the green/grey mix consideration). These digital communication technologies enable new value creation, reduction in environmental impact, and decentralised co-ordination in the electricity industry precisely because they make more of the network, and more of the participants in the network, transactive.

One of the hallmarks of smart grid technology is how it enables and reduces the cost of two-way communication. In electricity as in other industries, digital communication technology makes it possible and easy to have two-way communication and to use that communication capability to automate individual actions. As we have seen throughout society, as communication technology has proliferated it makes it easier and cheaper to engage in transactions. The implications of this for the electric power network are a smart grid that is a rich transactional environment, a market platform, a network connecting producers and consumers who contract and negotiate their mutual exchange of value (product, service) for value (payment). *A smart grid is a transactive grid.*

Take a non-electricity example – personal banking. Two innovations have transformed personal banking: the ATM and the internet. The digital communication technology that the internet comprises enables us to do our banking online instead of going to a branch or doing bank-by-phone. The transactions in which we engage with our bank are thus easier, quicker and cheaper for us. Furthermore, we can use this technology to automate our actions, such as scheduling recurring bill payments, or establishing trigger rules by which we receive alerts about our account status or activity. Digital communication technology enables us to bank any time, from anywhere. The value creation due to this transactive capability has been enormous, and has largely been in the form of consumer surplus/benefit (with some increases in retail banking profits before the current recession).

Digital communication technology lowers transaction costs. Transaction costs reduce the extent to which private parties engage in mutually beneficial exchange, thus as the internet has grown and our communication capabilities have expanded, our transactiveness has also increased dramatically. Banking is just one example; others include online shopping and eBay.

The implications of this transactive capability have been enormous: it has reshaped markets, firms and consumer expectations. Markets are increasingly global and competitive and we can engage in transactions with people on the other side of the world. But the most important implication of transactiveness for the electric power industry is the effect on firms. High transaction costs provide one reason for vertical integration, and have contributed to the vertically-integrated firms that have been the producers in this industry for a century – where transaction costs are high, firms make their transactions internal instead of through markets. But the transaction cost reductions arising from digital communication technology shift the margin at which it is profitable to organise transactions within a firm instead of through markets. If it is now cheaper to transact in markets, then transactive activity should shift from within-firm to between-firm, and the boundaries of firms should change. Vertically-integrated firms exist for several reasons (not the least of which in electricity is historical path dependence), and transaction costs provide only one reason, but lower transaction costs will contribute quickly to the increasingly stand-alone capability of both the generation and the retail portions of the electricity supply chain.

From the consumer's perspective, the implications of a transactive smart grid are profound. Take the personal banking experience and the GridWise Olympic Peninsula project example, and imagine what that kind of transactive capability would be like with respect to our energy use. Online home energy management, remote access, the ability to automate our electricity consumption decisions, the array of new products and services that could make use of this transactive functionality. Large industrial and commercial consumers already have such capability, but as technology prices have fallen and entrepreneurs have developed new products and services, a transactive smart grid brings this functionality into the home, creating a large range of value potential for consumers, producers and entrepreneurs.

A smart grid is a transactive grid

The reverse is also true. If a communication-rich electric power network does not take advantage of this transactive capability, we forsake all of this value creation. We still get value from the engineering-related optimisation of power flows, of fault detection and repair, and of distribution automation. But the engineering-related possibilities of a smart grid are only the tip of the iceberg: they are tweaks and improvements on the physical management of a closed-loop system. The true, meaningful, resilient and long-lived value proposition in smart grid is in enabling the multitudes of diverse, distributed, heterogeneous agents in the electric power network to exchange with each other for mutual benefit; in enabling a neighbourhood to form a microgrid and exchange among themselves; in enabling me to make a choice of whether to pay my employer for allowing me to charge my plug-in vehicle, or whether to sell my employer some of my stored electricity in the battery of my plug-in vehicle; and in allowing consumers to choose dynamic pricing and empowering them to use the technology and the price signals to control and manage their own electricity use. In other words, if a grid is not transactive, it is not a smart grid.

But what are the likely outcomes if we invest in such smart grid technology, but retain our historic method of regulating retail prices?

Smart technology, dumb pricing

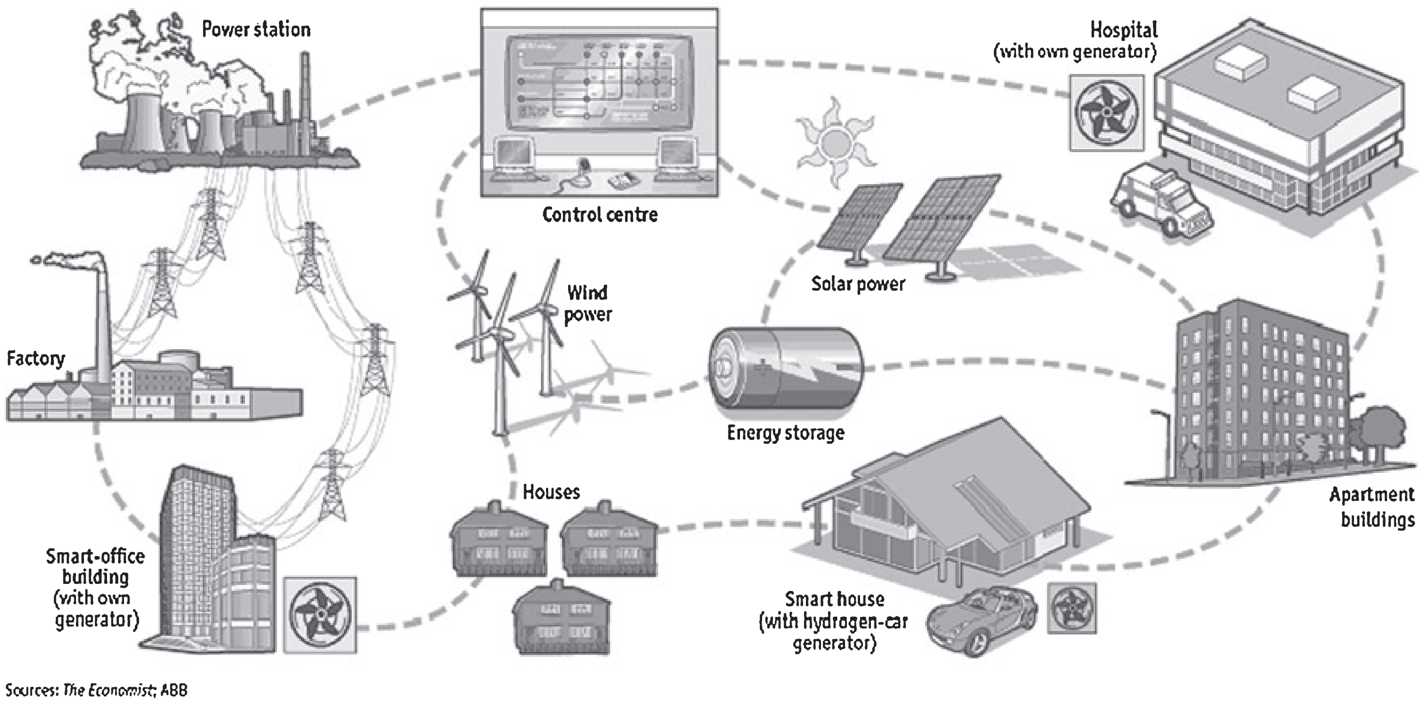
The GridWise Olympic Peninsula project and others suggest that smart technology and dumb pricing will nullify most of the potential consumer and system benefits of smart grid technology. Achieving the potential value creation from transactive end-use technology also requires enabling consumers to choose how much price volatility they are willing to accept, knowing that they have technology to manage their price responsiveness autonomously. At a minimum, transactive technologies require dynamic retail pricing if these innovations are to create value for consumers. Without dynamic pricing, the power system will fail to deliver efficiency and value to consumers. The 'one size fits all' of regulated and fixed retail rates is obsolete because of technological, institutional, regulatory and cultural changes that have created a diversity of products and services that the electricity industry can profitably sell to consumers. Dynamic pricing is necessary to maximise the value of technological innovation and other market reforms that characterise the most valuable, flexible and resilient power system; dynamic pricing also is, in and of itself, a valuable step in producing efficient and fair electricity markets.

Dynamic pricing, product differentiation and complementary technologies are the foundation of achieving decentralised co-ordination in the electric power industry. They bring timely information to consumers and enable them to participate in retail market processes; they also enable retailers to discover and satisfy the heterogeneous preferences of consumers, all of whom have private knowledge that is unavailable to firms and regulators in the absence of such market processes. Institutions that facilitate this discovery through dynamic pricing and technology are crucial for achieving decentralised co-ordination. Thus retail restructuring that allows dynamic pricing and product differentiation, that does not stifle the adoption of digital technology, and that reduces retail entry barriers is necessary if this value-creating decentralised co-ordination is to happen.

More generally, transactive end-use technologies make retail competition more feasible and beneficial. The inverse is also true: competitive retail electricity markets will be a platform for unleashing entrepreneurial creativity to enable consumers to get the most out of these technologies, and future ones that we cannot yet even imagine. The vibrant innovation in consumer electronics in the past 15 years illustrates this technology-institutions symbiosis that leads to consumer benefits and economic growth.

The present and future of the electricity system

These technological and institutional innovations would have implications beyond the individual consumer. Consider the electric power network as a system of interconnected individuals and physical assets. Historically, the technology, economics and business model in the industry has been a linear value chain with substantial homogeneity among the agents in the network, and with the delivery of value being uni-directional – the sale of generated electricity to end-use consumers. As Figure 1 suggests, technological



Sources: *The Economist*; ABB

Figure 1: The future smart grid value network

innovation is going to transform this traditional, linear value proposition.

Technological innovations in both supply and demand will transform the system into a value network, not a chain. The variety of resources and types of 'loads' increase, and now many agents have the technology that enables them to be a producer and consumer or a buyer and seller. These changes increase the complexity of the system. In such a complex system, adaptation to unknown and changing conditions is crucial for reliability and is also a way that consumers can benefit beyond the traditional benefits of generic electricity consumption. For example, home-level distributed generation and storage may improve the reliability of service for that homeowner, even if their normal consumption exceeds the capacity of their on-site generation. It also makes the network as a whole more resilient, because if an unanticipated shortage arises (such as an unplanned generator outage), a price signal would ripple through to the consumer indicating a higher price. This may induce a shift more use of the person's own generation or a reduction in demand by automatic changes in appliance settings. The individual could also sell electricity they generate to other consumers in the market. Similarly, if a homeowner has an electric vehicle, it is also an electricity storage device, which gives the owner the potential to be both a buyer and a seller of electricity. The home management system could be programmed and the vehicle used to sell stored electricity into the market, based on trigger prices that are set to reflect the owner's preferences.

The most effective and efficient system for enabling these adaptations is to use the technology's transactive capabilities to respond to price signals – in other words, enable these heterogeneous agents with their own private knowledge about their preferences and costs to co-ordinate using market processes.

Some policy implications

One of the largest challenges facing the electric industry and policy-makers today is the mismatch between regulatory and technological inertia within the industry and the vibrant, thriving economic and social dynamism that technological change has helped to create in nearly all other aspects of human society. Is it possible for regulatory institutions to be less subject to inertia and to be more adaptive to unknown and changing conditions such as innovation, changes in fuel costs and changes in environmental policy? Are regulators willing to enable the paradigm shift from control to co-ordination? Doing so would require regulators to shift their emphasis from retail rate structures and evaluations of cost recovery and towards retail choice, retail competition, market design and reducing transaction costs. It will also require reframing the idea of 'the public interest' away from its current narrow focus on low, stable retail prices to include environmental benefits and other more general concepts of consumer choice, product availability and consumer empowerment. Such an evolution of regulatory policy will mean incorporating more theories and practices from competition policy and an increased focus on information provision and consumer protection instead of retail rate determination.

One of the most effective institutional changes to enable decentralised co-ordination is to open retail electricity markets to competitive entry. Removing retail entry barriers and enabling retail competition would facilitate the promulgation of dynamic pricing options and product differentiation that could include green power and priority insurance, among other things. The decentralised and distributed network of retailers and customers can also contribute to grid resiliency and flexibility through more active participation in the market. Even if the magnitude of the shift in consumption is small, the effect may be large because of the non-linear relationship between peak load reductions and network reliability. A small load reduction at just the right time can keep the system from hitting capacity, can increase capacity utilisation and, in the long run, can reduce required investment in peak resources that sit idle much of the year. Letting go of some of the centralised economic and physical control would increase the resiliency of the system.

Bundling of retail electricity services with other services also has the potential to create value for consumers by making it easy and convenient for them to save money on their electricity bill in combination with other home services they consume, such as home security or home entertainment. For example, in regulated, vertically-integrated states in the USA a company such as ADT home security cannot enter the retail market and offer a bundled energy–home security service; in restructured US states (except for Texas) they have no profit driver to induce them to enter because of default service entry barriers. Reducing the regulatory barriers to enable us to learn if customers value such bundles would be a good thing, particularly for consumers and entrepreneurs.

By establishing preconditions for markets to function and creating an institutional environment in which they thrive, regulation will adapt to change because markets are complex adaptive systems that achieve ordered outcomes through decentralised co-ordination. By allowing markets to function, regulation will also benefit consumers by delivering differentiated products and services at different price points: note also that competition-facilitating regulation also enables entrepreneurial producers to profit from meeting the needs of consumers (who have diverse preferences and diffuse private knowledge). Market processes are positive-sum interactions in ways that traditional regulation cannot anticipate or duplicate.

Technology, automation, regulation and consumer empowerment

Economic growth and technological change have brought the electric industry and its regulation to a crossroads. Technological change from outside the industry has prompted changes in both regulatory institutions and business models, leading to the incremental disaggregation of the vertically-integrated firm in some regions of the USA and not in others. Simultaneously, increasing use of market transactions within this vertical value chain provides further strains on the existing institutional environment, both in the USA and in other countries as we see both incremental market liberalisation in the USA and the EU and privatisation of the industry in many other countries.

The transactive technology now exists to empower consumers to control and manage their own energy use as they see fit and to automate their choices. These technologies reduce the transaction costs of responding to dynamic price signals. The broader consequence is that transactive technologies enable us to overcome the knowledge problem, by making that 'edge intelligence' in consumer preferences active. This use of market processes to co-ordinate the choices of diffuse private agents is the hallmark of economic dynamism and of efficiency in a complex adaptive system. However, technology alone cannot accomplish this as long as regulatory barriers exist that prevent consumers from choosing products and services that have dynamic pricing. Technology and institutions are symbiotic.

And on the social value of autonomous, transactive technology, I will give the last word to Alfred North Whitehead: 'Civilization advances by extending the number of important operations which we can perform without thinking of them.'

1. This article is an extended version of a Beesley lecture delivered on 1 October 2009, and draws extensively on L. Lynne Kiesling (2008).
2. Kiesling, ibid., Chapter 2.
3. This project was funded through the US Department of Energy's GridWise programme, and project partners included IBM, Whirlpool and the local distribution utilities. For further information see Hammerstrom *et al.* (2007) and Chassin and Kiesling (2008).

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Decentralized Coordination through Digital Technology, Dynamic Pricing, and Customer-Driven Control: The GridWise Testbed Demonstration Project

David P. Chassin and Lynne Kiesling

The project highlights the idea that technology-enabled decentralized coordination can achieve the same, or better, economic and reliability benefits when compared to utility-focused centralized physical and economic control. Among the design's unique features was a retail double auction with five-minute market-clearing intervals that included residential customers as direct, active market participants.

Article Outline

I. Introduction

Current forecasts of both electricity demand and generation costs indicate that electricity prices are likely to rise over the next several years.[1] Meeting rising electricity demand using the traditional method – by building more generation, transmission, and distribution capacity – could cost up to $2000/kW,[2] and those costs are likely to increase due to rising construction costs.[3] Between rising costs and difficulties siting new plants and wires, the traditional approach is likely to be more costly and difficult to achieve than a new approach: using distributed digital end-use technology and dynamic pricing to enable consumers to control and manage their own electricity consumption.

Dynamic pricing can increase system reliability and capacity utilization, thereby delaying or avoiding infrastructure investments while saving consumers money in the process. Extensive research shows that residential customers can and do respond to dynamic pricing, and enabling end-use technologies increase the customers' ability to respond and the magnitude of the effects.[4] This article describes some of the results of the GridWise® Olympic Peninsula Testbed Demonstration, which looked specifically at the interaction of retail choice and enabling technologies. Rather than using traditional utility-centric centralized control to achieve reliable service, this demonstration employed a combination of smart technology and dynamic pricing to enable consumer-centric, decentralized coordination that achieved enhanced reliability, increased capacity utilization, and higher customer satisfaction.

The Olympic Peninsula Project looked at how consumers, especially residential customers, responded to real-time energy pricing information, and how consumers adjusted their energy consumption based on price changes. The project gave participants a choice to purchase electric power service through a variety of contract types; these contracts ranged from a fixed-type contract similar to those that have prevailed for residential customers over the past century, to real-time prices that could change every five minutes.

One important hypothesis tested was whether customers' responses to price changes were a function of the technology available to them. The project installed automated control technologies to allow industrial, municipal, and residential customers to automate their choice to change their energy consumption in response to price changes. For example, they could reduce their electricity consumption during times of peak demand or when prices were high and they had automated demand response. Residential customers also had smart appliances (including thermostats, water heaters, and clothes dryers) that could respond automatically to price signals. They could choose their balance between comfort and economy, and could customize and override their initial settings.

> Extensive research shows that residential customers can and do respond to dynamic pricing.

This year-long project demonstrated that this combination of distributed communication and control technology and dynamic pricing can achieve a variety of beneficial outcomes. Consumers saved money on their energy bills, and the amount they saved varied depending on the type of contract they chose. On average, consumers saved 10 percent on their electricity bills.

The decentralized coordination made possible through distributed technology and dynamic pricing also reduced peak demand by approximately 15 percent on average over the year of the project. Moreover, the price-induced demand response combined with distributed generation to reduce peak demand consistently over a course of several days during the project, sometimes by as much as 50 percent. This approach cost less than alternative methods of providing peak generation and increasing distribution capacity, and we suggest the approach might further be used to mitigate intermittency of renewable resources.

Two of the most meaningful implications of these results relate to investment and the barriers to achieving these benefits through the extension of such technologies and pricing. First, the project demonstrated that this decentralized coordination can alleviate the need to build expensive new infrastructure to address constraints on the distribution or transmission system during times of peak demand. If all customers were engaged in reducing peak demand, as in this project, peak electricity prices would be substantially lower, and construction of about $70 billion (over 20 years) of new generation, transmission, and distribution system infrastructure could be avoided, with those savings passed along to consumers.[5] Not only does that reduced investment requirement reduce long-term costs to consumers relative to what they would have been otherwise, it also reduces overall resource use and idle capacity, which has positive long-term environmental benefits. Second, regulatory institutions matter. The traditional cost-based structure of regulation, and the reticence of regulators to enable consumers to choose dynamic pricing, are the most substantial barriers to the wide-scale adoption of these feasible technologies, which enable reliability and resilience through decentralized coordination.

II. Structure of the Project

The Olympic Peninsula Project was a demonstration project, led by the Pacific Northwest National Laboratory (PNNL), testing a mixed residential, commercial, and industrial power distribution utility network with highly distributed intelligence and market-based dynamic pricing. Washington’s Olympic Peninsula is an area of great scenic beauty, with population centers concentrated on the northern edge. The peninsula’s radial electricity distribution network is connected to the rest of the network through a single distribution substation. While the peninsula is experiencing economic growth and a resulting increase in electricity demand, the natural beauty of the area and other environmental concerns mean that the residents want to explore options other than building generation capacity on the peninsula or building additional transmission capacity.

> The traditional cost-based structure of regulation, and the reticence of regulators to enable consumers to choose dynamic pricing, are the most substantial barriers.

Consequently, the Bonneville Power Administration (BPA) initiated an effort to address the transmission constraint through a so-called non-wires solution, among others. Siting a testbed where a real need for alternative supply solutions is already apparent amplifies the prospect that any demonstrated benefits may be clearly recognized and rapidly adopted. These considerations provided a strong incentive for selecting the Olympic Peninsula’s distribution system as a prime project site, where GridWise technologies could address a present need and be unambiguously demonstrated.

Thus this project tested the combination of enabling technologies and market-based dynamic pricing to investigate the effects of dynamic pricing and enabling technology on utilization of existing capacity, deferral of capital investment, and the ability of distributed demand-side and supply-side resources to create system reliability. Two issues were of primary interest in this project: (1) what dynamic pricing contracts are attractive to consumers, and how does enabling technology affect that choice? (2) to what extent will consumers choose to automate energy use decisions?

The project examined the impact of different pricing contracts and automation technologies on 116 broadband-enabled households with electric heating/cooling for the year April 2006 through March 2007. Of these, 112 remained in the project for the duration of the study. Each household received a two-way programmable communicating thermostat (PCT) with a visual user interface that allowed the consumer to program the thermostat for the home, and specifically to program it to respond to price signals if desired. Some households also received dryers equipped with a Grid Friendly™ appliance (GFA) controller chip developed at PNNL, which enabled the appliance to receive price signals and be programmed to respond automatically to those price signals. Consumers could control the sensitivity of the appliance through the PCT settings.

These households also participated in a market field experiment involving dynamic pricing. While they continued to purchase energy from their local utility at a fixed price, they also received a cash account with a pre-determined balance. The received the balance remaining each quarter and the account was replenished based on their historical energy consumption. The energy use decisions they made would determine how much was deducted from their cash account, and they were able to keep any difference as profit. The worst a household could do was a zero balance, so they were no worse off than if they had not participated in the experiment. At any time, customers could log in to a secure Web site to see their current energy use and how effective their energy use strategies were.

Upon signing up for the project the households received extensive information and education about the technologies available to them and the kinds of energy use strategies made possible by these technologies. They were then asked to choose a retail pricing contract from three options: a fixed-price contract (based on BPA’s price forecast), a time-of-use (TOU) contract with a variable critical-peak pricing (CPP) component that could be called in periods of tight capacity, or a real-time price (RTP) contract that would reflect a retail-level market-clearing price in five-minute intervals.

The RTP was determined using a uniform price double auction, in which buyers (households, commercial, and industrial) submit bids and sellers (wholesale and retail-level distributed generation) submit offers simultaneously. The digital technology in the household enabled residential customers to participate actively in such frequent markets because they could automate the bidding of their demand functions into the market. This project was the first in which a double auction retail market design was tested in electric power, and the use of a retail double auction with residential customers in the market is one of the unique features of this market design.

> Households participated in a market field experiment involving dynamic pricing.

Using ranked contract preferences, the households were then divided fairly evenly among the three contracts types and a control group that received the enabling technologies and would have their energy use monitored, but did not participate in the dynamic pricing market experiment. All but 11 percent of households not placed in the control group received either their first or second choice (49 percent and 16 percent, respectively); interestingly, nearly 90 percent of the households ranked RTP as their first or second choice. This result counters the accepted wisdom that residential customers want only reliable service at low, stable prices, but may be enhanced by an early-adopter effect.

Of the 116 households, 30 were in the fixed-price contract, 30 were in the RTP contract, 31 were in the TOU contract, and 25 were in the control group that received the digital technology but did not participate in the market experiment.

The control group participants were not charged for their energy consumption. Fixed-price group participants were charged 8.100 ¢/kWh. The TOU participants were charged under two different rate structures depending on the season. During the period fall, winter, and spring season (Oct. 1–July 24) the off-peak (9:00 AM–5:59 PM and 9:00 PM–5:59 AM) price was 4.119 ¢/kWh and the on-peak (6:00 AM–8:59 AM and 6:00 PM–8:59 PM) price was 12.150 ¢/kWh. During the summer period (July 25–Sept. 30) the off-peak (9:00 PM–2:59 PM) price was 5.000 ¢/kWh and the on-peak (3:00 PM–8:59 PM) price was 13.500 ¢/kWh. A single CPP event was called Nov. 1 from 2:00 AM to 6:00 AM with a price of 35.000 ¢/kWh. The RTP participants were charged the price of energy as cleared every five minutes by a retail-level market.

The system was operated with different constraints on the feeder at different times of year. From April 1 to Sept. 22, the feeder capacity was set to 1,500 kW and the Mid-Columbia wholesale price of power reported by Dow Jones was bid at the level. From Sept. 22 to Dec. 8, the feeder capacity was reduced to 500 kW, and from Dec. 8 to March 31, it was increased to 750 kW.

Figure 1 represents how the active RTP households and the DG resources could interact to determine the market-clearing price in five-minute intervals.

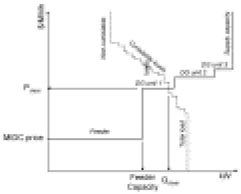

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Figure 1. Representative Supply and Demand in Five-Minute RTP Market

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III. Results of the Project

We focus on some of the most important economic results of this project: household energy consumption, prices paid, household savings, and changes in overall load duration. Table 1 presents the average hourly household energy consumption by contract group. The average household in the TOU contract group consumed the least electricity per hour (1.420 kW), followed by the average fixed-price customer (1.790 kW), the average RTP customer (2.100 kW), and finally the control group (2.116 kW).

Table 1.

Mean and Standard Deviation of Hourly Household Energy Use by Group.

Group	**Mean (kW)**	**Standard Deviation**	**Number of Observations**
Control	2.116	1.25	8759
Fixed price	1.790	0.84	8759
TOU	1.420	0.77	8759
RTP	2.100	1.00	8759

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These consumption patterns differ statistically from each other (based on nonparametric Kruskal–Walls tests of medians across groups). Thus, we found that the type of dynamic pricing contract shapes individual behavior. Furthermore, note that the incentives inherent in different forms of pricing led to different average consumption beyond just having the technology, as was the case for the control group. This result suggests that simply the transparency and information provided by the technology does not necessarily reduce electricity consumption as effectively as the combination of the technology and the dynamic pricing with its embedded economic incentives.

The consumption data presented in Table 1 suggest that the TOU contract households consumed less energy than the other customers. After controlling for price response, weather effects, and weekend days, the TOU group's overall energy consumption was 20 percent lower than the fixed-price group's.[6] This result indicates that the TOU (with occasional critical peaks) pricing induced the greatest overall energy conservation and reduction in electricity use.

Table 2 reports the average hourly price per MWh by contract group. This was computed as a blended average by dividing the total energy consumed by the total payments made for each contract group. In the case of the control group, this quantity could not be computed because they did not pay for energy used.

Table 2.

Mean and Standard Deviation of Hourly Average Price/MWh by Group (dollars).

Group	Mean ($/MWh)	Standard Deviation	Number of Observations
Control	n/a	n/a	n/a
Fixed price	81.000	0.000	8759
TOU	63.271	35.904	8759
RTP	49.198	47.462	8759

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The low average price for those on the RTP contract indicates that the RTP customers used their automation and control capabilities to shift their use to less expensive times. The customer savings achieved corroborate this observation. Figure 2 shows average household savings by contract group.

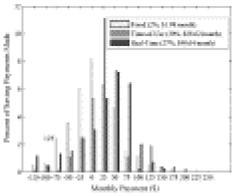

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Figure 2. Monthly Savings Estimate by Contract Group

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Participants in the fixed-price contract received about 2 percent savings relative to the control group; the TOU group saved 30 percent and the RTP group saved 27 percent. Note the difference in the distribution of the savings across the three groups. The RTP savings are skewed substantially to the right of the other two groups. This distribution of RTP savings indicates the significantly greater savings earned by the RTP customers who selected the most economical appliance settings, relative to those who selected more comfort and did not earn such savings. In terms of peak demand reduction, the RTP group saw peak consumption decreases of between 15 and 17 percent relative to what the peak would have been in the absence of the dynamic pricing. We also compared the actual energy use to the counterfactual energy use, i.e., the amount that would have been consumed at the average price in that market period instead of the market-clearing price as determined by the double auction. Figure 3 shows the actual and the counterfactual load duration curves (graphed logarithmically) divided among three system condition categories: when the distribution feeder was unconstrained, moderately constrained, and severely constrained. In essence, a load duration curve shows the distribution of consumption over time; if consumption were distributed uniformly, the load duration curve would be a straight line, and capacity utilization or load factor would be the same at all times. Flattening the load duration curve, which indicates shifting some peak demand to non-peak hours, improves capacity utilization and reduces the need to invest in additional capacity, for a given level of demand. The peak load reduction of the RTP group is seen at the top left corner, where the actual curve is substantially below the counterfactual curve. Note Figure 3(c) in particular, which shows how extensively the RTP market and demand response automation reduced demand relative to the level of demand without the combination of the RTP market and the distributed residential automation technology. A 15 to 17 percent reduction is substantial, and is similar in magnitude to the reductions seen in other projects, such as the California Statewide Pricing Pilot.[7]

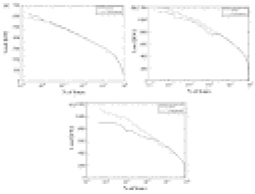

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Figure 3. Actual and Counterfactual Load Duration Curves for (a) Unconstrained, (b) Moderately Constrained and (c) Very Constrained Systems

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In addition to the reduction in peak demand in the RTP group, consumers also had a shifted load shape as a result of the dynamic pricing and the automated technologies that responded directly to market price signals. Figure 4 shows the actual and counterfactual thermostat loads for thermostatically controlled space conditioning of RTP contract homes during the most-constrained and least-constrained periods on the distribution feeder. Because all participant bids for RTP contracts were recorded when the market cleared every five minutes, and the bid price formula based on the thermostat status is reversible given the information gathered during the project, both the actual and the counterfactual energy could be computed for each market period.

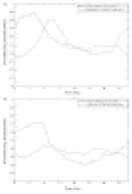

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Figure 4. Diurnal RTP Group Heating End-Use Load (a) Constrained Feeder, High Demand, (b) Unconstrained Feeder, Low Demand

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The RTP induced an interesting shift in this automated consumption in both constrained and unconstrained feeder conditions. When demand was high and the feeder was constrained, the shift of demand from peak to off-peak was large, induced by the differential between peak and off-peak market-clearing prices. On unconstrained feeder days, however, the moderation of price volatility meant that the thermostats were sensitive to smaller diurnal price variations. While the transactive control strategy did not explicitly forecast future prices, the diurnal nature of the price movements themselves effectively induced opportunistic pre-heating or pre-cooling. The use of pre-heating/pre-cooling is generally viewed as an essential mechanism to mitigate the effect of load curtailment rebound phenomena. Effective pre-use strategies can be very difficult to engineer, and it is encouraging to see that market-based strategies are at least as effective as administered ones. Figure 4 shows the diurnal load duration curves for the RTP group during the period of constrained feeder (4a) and unconstrained feeder (4b).

Finally, the project's participants were very satisfied with the technology and the pricing with which they experimented during the project. Final project participant surveys indicate that 80 percent of participants were either very satisfied (51 percent) or somewhat satisfied (29 percent) with the end-use technology, and that 82 percent were either extremely likely (48 percent) or very likely (34 percent) to participate in a program like this one if it were offered again.[8]

IV. Conclusion

The GridWise Olympic Peninsula Testbed Demonstration is the most significant demonstration to date that dynamic pricing and digital end-use technology combine to empower consumers to manage their own electricity use and save money in a user-friendly way. Moreover, these individual choices in aggregate led both to immediate and sustained reductions in peak demand. One implication of these results is that dynamic pricing and enabling end-use technology can improve capacity utilization and forestall or eliminate the need to invest in costly and unpopular generation, transmission, and distribution assets.

A unique feature of the tested market design was a retail double auction with five-minute market-clearing intervals that included residential customers as direct, active market participants. The positive individual and system results suggest that further implementation of such a retail market design would benefit residential customers, including those who do not choose a RTP contract.

The Olympic Peninsula Project also demonstrated how new business models and regulatory approaches can overcome institutional barriers. Dynamic pricing and retail customer choice offer both individual and system benefits, but substantial barriers have precluded them from evolving for residential customers. Two of the largest social and cultural barriers are risk aversion on the part of utilities, who are heavily invested in their existing business models based on rate recovery through physical (generation, transmission, and distribution) assets, and risk aversion on the part of regulators, who have traditionally believed that the public interest and consumer protection are best served by fixed, regulated retail prices. This project has demonstrated how changing those beliefs, and the policies arising from those beliefs, can benefit consumers, utilities, and regulators.

In brief, this project highlights the idea that technology-enabled decentralized coordination can achieve the same, or better, economic and reliability benefits when compared to utility-focused centralized physical and economic control. The dramatic transformation of digital technology in the past few decades has decreased transaction costs and increased the extent of feasible decentralized coordination in this industry, just as we have seen occur in so many other industries. Institutions, which structure and shape the contexts in which such processes occur, provide a means for creating this decentralized coordination. In particular, regulatory institutions affect whether or not this coordination can occur. Thus, effective regulation should not focus on allocation, but rather on decentralized coordination and how to bring it about. A focus on decentralized coordination means a focus on market processes, which are adaptive institutions that evolve along with technological change.

[1] Federal Energy Regulatory Commission, *Increasing Costs in Electric Markets*, June 19, 2008, at 2, available at http://www.ferc.gov/legal/staff-reports/06-19-08-cost-electric.pdf.

[2] D. Hammerstrom *et al. Pacific Northwest GridWiseTM Testbed Demonstration Projects, Part I: The Olympic Peninsula Project*, 2007, at 1.1, available at http://gridwise.pnl.gov/docs/op_project_final_report_pnnl17167.pdf.

[3] FERC, *supra* note 1, at 6.

[4] Lynne Kiesling, Deregulation, Innovation and Market Liberalization: Electricity Regulation in a Continually Evolving Environment (Routledge: 2008), Ch. 4.

[5] W.S. Baer *et al.*, *Estimating the Benefits of the GridWise Initiative*, RAND, Santa Monica, CA, May 2004, at 28.

[6] Kiesling, *supra* note 4, Ch. 4 Appendix.

[7] Charles River Associates, *Impact Evaluation of the California Statewide Pricing Pilot*, Oakland, CA, 2005.

[8] Hammerstrom *et al.*, *supra* note 2, at A.11.

Vitae

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