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

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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.

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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.

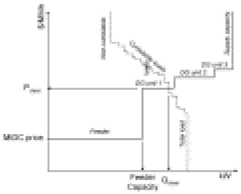

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Figure 1. Representative Supply and Demand in Five-Minute RTP Market

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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.

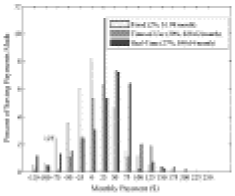

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Figure 2. Monthly Savings Estimate by Contract Group

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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]

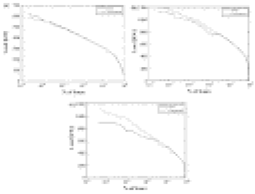

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Figure 3. Actual and Counterfactual Load Duration Curves for (a) Unconstrained, (b) Moderately Constrained and (c) Very Constrained Systems

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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.

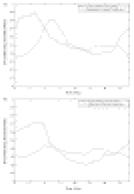

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Figure 4. Diurnal RTP Group Heating End-Use Load (a) Constrained Feeder, High Demand, (b) Unconstrained Feeder, Low Demand

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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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Lynne Kiesling is a Senior Lecturer in the Department of Economics at Northwestern University, and in the Social Enterprise at Kellogg (SEEK) program in the Kellogg School of Management at Northwestern University. At Northwestern she is also a Faculty Member in the Northwestern Institute on Complex Systems (NICO) and a Faculty Affiliate in the Center for the Study of Industrial Organization (CSIO). She is also currently a member of the GridWise Architecture Council, a group of 13 experts volunteering their time to articulate the guiding principles for an intelligent, transactive energy system of the future, and to guide and promote measures to transform the nation’s electricity system into a more reliable, affordable, secure network in which users collaborate with suppliers in an information- and value-rich market environment.