

The Effects of Regulation and Utility Ownership on Technology Adoption:

A Case Study of Demand Response in the U.S. Electricity Market

Allen McGonagill

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Executive Summary

The United States retail market for electricity is reacting to a series of technology shifts, from renewable energy, to plug-in vehicles, to smart-grid technologies. These technologies have the potential to create jobs while reducing the impact of electrical use on the environment. Regulators in particular need to have an understanding of how electric utilities make technology decisions in order to write policies which encourage efficient use of these new technologies. By using demand response in the United States as a case study for adoption of new technology, this paper investigates the effects of regulatory policy and utility type on the success of demand response adoption. The analysis herein uses the results of the FERC 2010 Survey on Demand Response and Advanced Metering to look at the implementation of demand response on a national level. This study focused on how investor-owned utilities, rural electric cooperatives, and public utilities made choices about demand response in the retail electricity market.

Although many factors play a role in the effectiveness of demand response, this paper hones in on three potential drivers of demand response success: (1) the effect of regulatory policies such as decoupling and deregulation on a utility's decision to create a program, (2) the effect of ownership on how innovative demand response programs are, and (3) the effect of ownership on customer enrollment into demand response.

1. There is still no national consensus on the overall effectiveness of deregulation of electricity markets or the decoupling of utility revenues, and when making these large-scale changes the impacts on industry-wide innovation should be taken seriously. As regulatory policies about market structure vary by state, a state-level perspective is taken to measure the correlation between policies and the popularity of demand response. These regressions offer insight into the correlations between market structure and technology adoption. This paper finds that deregulation has a negative correlation with demand response adoption, but no significant correlation between decoupling and demand response. Deregulation is correlated with 5.6 to

7.6% less utilities in the state with at least one demand response program. Decoupling had a slightly positive effect on demand response uptake but the correlation was not significant. These results are only correlations and time-series data with more observations would be required to draw a more certain cause-and-effect relationship.

2. Utilities implementing demand response must choose between price and incentive-based programs. A utility's ownership structure and degree of profit motive might impact whether it adopts the more innovative price-based programs. This paper finds that price-based demand response programs are most popular with investor-owned utilities (IOUs). Of utilities with at least one program, IOUs are 22.5% more likely than cooperatives to have at least one price program once other factors such as price and geographic region are controlled for.
3. Once a program is established, the utility must engage and motivate its customers to enroll in the program. These data show that customers respond differently to demand response depending on the type of utility coordinating the program. Cooperatives have 9.7% higher enrollment rates than IOUs, which might indicate that cooperatives develop stronger relationships and better customer service. Managers of IOUs and public utilities can look to cooperatives' customer interactions as a model when technology adoption requires interaction with customers.

Overall, deregulation seems to have a negative impact on technology adoption, IOUs tend to choose price-based programs more frequently than other utility types, and cooperatives achieve the highest participation rates. These results are dependent on the factors included in this analysis and if important factors were not controlled for these correlations might be false. This paper should make regulators pause to think about the implications of their policies and how they can best incentivize different types of utilities; however, it does not make uniform suggestions about state policy. State electricity markets vary too widely for any singular approach to incentivize demand response or other smart grid technologies. Public utilities commission's can put their state in the best position possible to take advantage of the smart grid by understanding that market liberalization is not necessarily a driver of innovation.

Dear Reader,

This thesis has been prepared to satisfy a variety of audiences. Hopefully, these results are of interest to public utilities commissioners, the Federal Energy Regulatory Commission, utility operators, policy-makers, and economists.

There are a number of sections and they will not be applicable to each audience. To make this paper more accessible, I have summarized the content of each of the sections in lieu of a formal table of contents. I also make recommendations about which sections will be of value to different readers.

Enjoy.

Reading Recommendations:

Public utilities commissioners- Read Section 1, skim Section 2, descriptive statistics in Section 3, skim Section 4, Section 5 and 6 are the most important to read.

Federal Energy Regulatory Commission- Skim Section 1 and 2, read the descriptive statistics in Section 3 and Sections 4-6 in their entirety.

Utility operators- Skim Section 1 and 2, read Section 3, skim Section 4, read sections 5 and 6.

Policy-makers- Read all sections if not familiar with the intricacies of demand response.

Economists- Read all sections if not familiar with the intricacies of demand response.

Description of Sections:

Pg. 1 Section 1: Introduction

This section explains what demand response is and why it is important to the United States both environmentally and economically. It shows how demand response adoption can be used as a lens to look at other types of technology adoption in electricity markets.

Pg. 4 Section 2: History and potential of demand response

The opening of this section discusses the history of demand response in the United States and the projections for peak reduction potential. Then I explain how technology, legislation, and market reform can impact these projections. This introduces readers to advanced metering infrastructure (AMI), PURPA, market deregulation, and revenue decoupling.

Pg. 11 Section 3: Data set and descriptive statistics

This section details how the data set for this analysis was created and describes the distribution of key variables. The discussion focuses on the types of utilities (i.e. cooperatives), types of demand response programs (i.e. time-of-use), and the regional distribution of deregulation/decoupling. This should familiarize the reader with some terminology of demand response programs and give an updated snapshot of demand response as reported by the FERC 2010 survey.

Pg. 20 Section 4: Conceptual framework

To organize the research and results, I develop a framework for what variables might impact demand response and place them into three categories: regulatory atmosphere, entity structure, and consumer characteristics. These variables determine three decisions regarding demand response: whether utilities create demand response programs, what type of demand response programs are created, and whether customers enroll in these programs. This section includes a review of both economic and industry literature on demand response as it applies to these variables. Scattered through this discussion are the 5 hypotheses that were tested in this paper.

Pg. 34 Section 5: Results

This section interprets the results of regressions that were run to test the hypotheses. In addition to interpreting the output of regressions, the discussion postulates potential relationships between demand response and the control variables.

Pg. 44 Section 6: Conclusion

This is a summary of the findings and how they could impact adoption of technology by utilities. It suggests the implications of regulation and recommends areas of improvement (particularly for investor-owned utilities). Potential areas of future research are outlined briefly.

Section 1: Introduction

In the United States, both policy makers and leaders in the energy industry are pushing for the advancement of a smarter electricity grid. The “smart grid” has been included in President Barack Obama’s energy plan, the Energy Independence and Security Act of 2007 and the Waxman-Markey bill (H.R.2454).^{i,ii,iii} Electric utilities and technology companies from National Grid to Siemens have embraced the smart grid by developing new divisions and promoting government involvement.^{iv,v} The smart grid is lauded for its potential to create a new segment of the U.S. economy and reduce greenhouse gas emissions. These benefits are particularly attractive given the current economic crisis and estimates that greenhouse gasses must be reduced by 50% by 2050 to avoid the worst case scenarios of climate change.^{vi} Greenhouse gas reductions from the electricity sector will have to come from a more efficient system of distribution and generation, as consumption has grown at 1.9% per year from 1990-2007.^{vii} Even with a depressed economy, peak electric consumption is projected to grow by 1.66% per year until 2014.^{viii}

Reducing peak energy consumption can result in economic benefits for utilities and reduce greenhouse gas emissions. Utilities meet demand for electricity by producing power with the lowest marginal cost, and have to use more expensive sources of power to meet peak demand than low demand.^{ix} If a utility owns a wind farm and a coal plant, it will operate the wind farm all day, but only operate the coal power plant to meet peak demand (Figure I). Renewable energy has a low marginal cost and will provide power during times of low demand where it is installed; however, utilities without renewable energy might get their lowest cost power from coal, nuclear, or hydroelectric sources. Therefore, reducing peak demand will do more to reduce emissions as renewable energy becomes more prevalent. Regardless of emissions impacts, utilities save money by operating their most efficient plants and have incentive to smooth out demand loads. This can affect the general populous as cost savings from this would be passed onto customers.

Low Demand



Photo: Morten Mitchell Larod

Peak Demand



Photo: Ian Britton

Figure I: Meeting Peak Demand

Additionally, electric utilities have to scale generation and transmission capacity to meet peak demand. Regulation requires excess infrastructure above the average levels of peak demand in case of supply outages or extreme demand spikes, creating built-in redundancies.^x Historically, power generation in the United States has 20% excess capacity and the average utilization rate of generators is about 55%.^{xi} Reducing peak demand can reduce the construction of otherwise unnecessary infrastructure, which reduces greenhouse gas emissions and environmental impacts associated with power plant construction while avoiding large capital costs for utilities. Initiatives which lower peak capacity reduce the cost of electricity by deferring investments in generation, transmission, and distribution equipment.

One strategy with the potential to significantly reduce peak demand in the United States is demand response (DR). DR programs incentivize electricity consumers to shift energy usage patterns in response to fluctuations in demand. On a daily basis, electricity consumption is lowest in the early morning, peaks during the afternoon, and declines throughout the evening. Utilities can create smoother demand for electricity by getting consumers to use electricity earlier and later in the day. There are two types of demand response programs used to shift electricity consumption:^{xii}

1. Incentive-based programs: Customers are paid to cede control over certain equipment, i.e. hot water heaters, to the electric utility. Utilities might have direct control over the equipment or customers might have to respond to signals from the utility.
2. Price-based programs: Utilities charge different rates for electricity at different times of the day. Customers adjust their electricity demand in response to varying price signals.

In 2009, demand response was responsible for a 5% reduction in United States peak demand. Models predict that under optimal conditions, demand response could reduce peak demand by 20% by 2019.^{xiii} Due to the potential of demand response, it has become increasingly popular over the past decade. In a recent survey of 181 stakeholders in the electric industry, more accurate pricing of electricity was the 2nd most popular mechanism “to overcome the impediments facing renewable energy and energy efficiency”.^{xiv} Over 60% of respondents were in support of variable pricing of electricity, potentially utilizing a formal demand response program. Demand response has been well received by customers as well as policy makers. A recent survey reported that electricity consumers had 85-99% satisfaction with DR programs.^{xv}

The recent rise in demand response activity shows that DR programs have potential; however, little is known about what drives their adoption and success. The number of entities offering DR increased by 317% since 2006, so it is imperative for regulators and utility operators to have a firm understanding of the forces driving this trend.^{xvi} This paper investigates which factors affect demand response program implementation in retail markets. It looks at the correlation between DR choices and (1) regulation by public utilities commissions and (2) utility type. Why do utilities initiate DR programs and how do they choose between price and incentive DR programs? Using survey data published in early 2011 by the Federal Energy Regulatory Commission (FERC), the paper focuses on what factors affect three DR outcomes: (1) whether utilities implement a demand

response program, (2) whether those programs offer time-varying rates or pay enrollees a stipend, and (3) consumer participation in demand response programs.

This is one of the first papers to use the 2010 FERC data set. Although FERC has published descriptive statistics of their survey, there have been no econometric regressions run on this data. Given the recent changes in regulatory policy and smart grid technologies, this data can be used to shed light on the current state of demand response and its regulatory environment. The availability of FERC's data allows this paper to investigate questions that have been previously unanswerable. Does the higher price elasticity of residential consumers in the South create increased opportunities for demand response? If so, customers in the South might respond well to price-based programs which allow them to utilize their more elastic demand. Does regulatory structure impact utility adoption of demand response and potentially other technologies? Ultimately, each regulatory body and utility must make demand response decisions based on the specific market or state, but this study provides insight into some overarching trends in demand response adoption in the United States.

Section 2: History and Potential of Demand Response

Though demand response has become a component of the smart grid movement, the concept originated as a solution to the oil crises of the 1970s. In response to the high oil prices of the 70s, consumers demanded more electricity, so utilities developed DR programs throughout the 1980s to keep up with demand. Over time, oil prices collapsed and utilities built up infrastructure to compensate for supply shortfalls. This resulted in an excess supply of electricity. For some time, DR programs cost more money to operate than they saved in generation costs. Customers were paid to enroll in programs but the DR capacity was never called upon due to excess supply. Despite their inefficiency, state regulators unknowingly subsidized DR programs throughout the 80s.^{xvii, xviii} In the

early to mid 1990s, demand response lost momentum and the capacity of DR programs fell by 33% by 2006.^{xix} The history of demand response shows that it can be inefficient if it is valued as a “source” of energy which can be used to meet high levels of demand instead of being treated as a “reduction” in demand.¹ As such, we must take care not to repeat the mistakes of the 1980s where programs were implemented despite their inefficiencies.

In the past 4 years, utilities have established demand response programs at a rapid rate; however, much of the total demand response potential is still untapped. From 2006 to 2010 the number of utilities or other energy companies offering demand response increased from 126 to 525.^{xx} Of the total number of utilities in the United States, 16% have established at least a single program.² These results might be skewed upwards if the survey results have gotten higher response rates from 2006-2010, but response rates have actually declined from 55% to 52%.³ The total potential for these DR programs is 7.6% of U.S. peak demand, up from 5.0% in 2006.^{xxi} Though this increase in demand response is impressive, there is still room for growth. FERC has produced projections of demand response growth potential under multiple scenarios and current growth trends mirror the “business-as-usual” scenario, which is the scenario with the lowest penetration of demand response. There is a large gap between projected potential under a fully coordinated push for DR and the results that we have seen to date. Furthermore, studies show that current DR programs often overestimate their MW potential when the programs are called upon by the utility, meaning that there might be more room for growth than projected.^{xxii, xxiii} In fact, FERC estimates that less than a quarter of national DR potential is currently being used.^{xxiv}

¹ The difference between “supply” and “demand reduction” is that energy suppliers do not receive revenue for demand reductions. The economic benefit to the energy supplier is their reduced cost of supplying energy less the revenue they would have received from higher levels of demand.

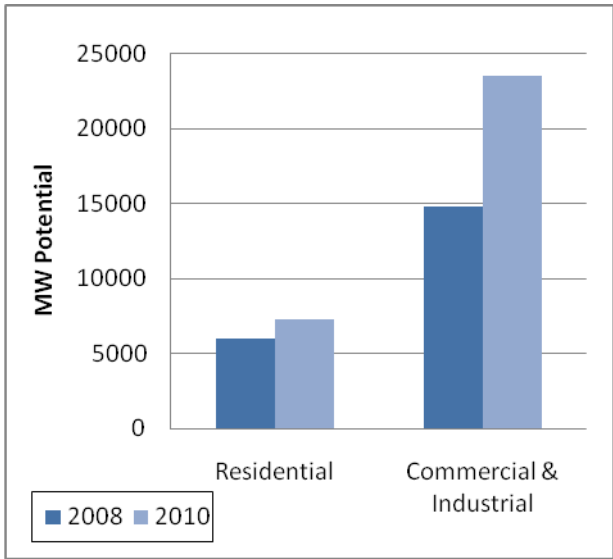
² This is based on the 2009 form EIA-861 from the U.S. Energy Information Administration, which reports utilities by the state level. Like the FERC data set, this counts a utility spanning three states as 3 different utilities.

³ The number of utilities increased by 4, which is a 0.12% increase.

When analyzing the growth in demand response it is important to distinguish between wholesale and retail programs. Slightly under half of demand response takes place on the wholesale market (see Appendix I). The wholesale electricity market provides intermediary power but does not deliver power to an end-use consumer. Electricity on the wholesale market is sold by independent power generators to utilities or between two utilities. Wholesale demand response can be called upon by a utility in the market in an emergency in order to reduce demand. Demand response in the wholesale sector currently provides 41.7% of total DR potential.^{xxv} Therefore, curtailment service providers and ISOs have a large impact on DR. Curtailment service providers, such as ENERNOC and Constellation, manage large blocks of DR and sell these to utilities. Independent system operators (ISOs) can create demand response programs independently of local utilities.⁴ Despite the potential of wholesale DR, this study focuses on retail demand response because it is not geographically confined to states with wholesale markets and the results are more applicable to the application of other smart grid technologies. This paper does not advocate for wholesale DR over retail DR, but tries to use the retail market's adoption of DR as a case study for the adoption of future technology.

The increase in retail demand response potential over the last 4 years has been driven by large commercial and industrial entities while residential potential has remained relatively constant (see Figure II).^{xxvi} Since 2008, commercial/industrial DR has increased 59% while residential DR only increased 21%.^{xxvii} The

Figure II: Retail DR in the U.S.



⁴ ISOs oversee the coordination and monitoring of the electrical grid in their geographic region.

focus on commercial and industrial programs has been caused by lower up-front cost to establish programs and higher MW potential per customer enrolled. Engaging residential customers in demand response would require larger scale DR programs, but could tap into an underutilized pool for DR.

Utilities are not solely responsible for how quickly demand response is spreading in the retail sector. If retail demand response is to reach its full potential, more has to be done than influencing the operators of utilities. Demand response decisions also depend on technological, legislative, and market-based factors. Each of these external factors is discussed individually in the sub-sections below. Overall, it is important to note that utilities have to balance many external factors when making demand response decisions. By altering these external factors, regulators, legislators, or other actors can affect demand response outcomes.

Section 2.1: Technology and DR

DR is being implemented conjointly with advanced metering infrastructure (AMI) which allows utilities to bill customers at different rates depending on current demand. Though AMI is relatively new, it has gotten momentum due to grants from the American Reinvestment and Recovery Act of 2009.⁵ Utilities install meters to respond to power outages more efficiently, and often include DR programs as a way to gain approval from their regulatory commission or because the infrastructure is already in place, especially when trying to penetrate residential and small commercial users. Economists believe that metering costs is one of the largest barriers to DR implementation.^{xxviii, xxix} At the time of the 2006 FERC survey, AMI use in the U.S. was 0.67%, but over 5% of meters had AMI technology without being used to their capacity.^{xxx} By 2010, AMI use increased to 8.7% as many of these unused meters were utilized and new infrastructure was laid down.^{xxxi} Under the most conservative FERC projections, AMI penetration will exceed 40% by

⁵ Grants have gone to NSTAR in Massachusetts and Con Edison in New York City among other utilities.

2019.^{xxxii} The decisions of where this infrastructure will be placed and by what types of utilities will affect where demand response will occur. As much of this infrastructure will be approved by public utilities commissions, it is important for these commissions to understand the motivations and tendencies of the utilities requesting approval.

Section 2.2: Legislation and DR

There have been no nation-wide legislative mandates for utilities to develop DR programs, but the government has started to create support and funding structures together to develop DR more comprehensively. The recent legislative push for DR began in 2005 with The Energy Policy Act (EPACT), which explicitly stated that the energy policy of the United States would eliminate barriers to demand response at both the wholesale and retail level.^{xxxiii} EPACT also mandated that FERC provide an assessment of DR with recommendations regarding energy policy.

In 2007, congress enacted the Energy Independence and Security Act (EISA), which amended the Public Utility Regulatory Policies Act (PURPA) of 1978, directed FERC to develop a National Action Plan for demand response, and authorized funding of \$30 million over 3 years towards the National Action Plan.^{xxxiv} The amendments to PURPA created a new Standard which requires all utilities to offer and provide customers with time-based electricity rates. However, instead of mandating nation-wide compliance, PURPA required that each utility commission decide if the Standard was appropriate for their state. To date, no state has adopted the Standard as it was worded by PURPA.^{xxxv} There is still not consensus on how to best implement demand, and although states can create electricity markets that are conducive to demand response, utilities are ultimately responsible for developing demand response in the retail market.

Section 2.3: Market structure and DR

In an attempt to create more efficient electricity markets, public utilities commissions have experimented with 2 policy-based market overhauls: decoupling and deregulation. These two

policies impact how utilities operate and impact different types of utilities differently. Demand response adoption and other technology choices could be affected by the choice to enact these two policies. Decoupling changes the metrics by which state regulators compensate utilities while deregulation reduces the oversight of state regulators, opening electricity markets to competition. In markets without decoupling, utilities' revenue is based on how much energy they sell. Therefore, they are unlikely to implement demand response programs which can reduce sales. In markets without deregulation, regulators can encourage new technologies even if they are not profitable. In deregulated markets, demand response and other technologies will only be implemented if they give utilities an advantage in a competitive market.

In markets without decoupling, utilities earn a fixed rate per kilowatt hour (kWh) which is set by the regulatory body to give the utility a fixed return. The rate is determined during a "rate case" proceeding in which the utility and regulator agree upon a fair return on their capital investments. Using this return, the regulator calculates a target revenue which is divided by projected energy sales to establish a fixed rate per kWh. Within a given year, a utility can increase revenue by selling more electricity, because it will earn a fixed rate/kWh. A recent survey of demand response results showed electricity consumption reductions of 10-15%.^{xxxvi} This reduction in consumption would reduce revenue for a utility. In "decoupled" states, utilities are instead compensated based on the number of consumers they serve or some other metric. Decoupled utilities still charge a fixed price/kWh, but the price is calculated based on a target revenue per customer class. Deviations from the target revenue/customer are adjusted in the next year's price/kWh. California, Massachusetts, and Connecticut have permanently decoupled revenues for all utilities, while 6 other states are running either pilot programs or have decoupled selected utilities.^{xxxvii} An alternative compensation structure, called "lost revenue adjustments", has emerged alongside decoupling. Revenue adjustment does not break the tie between sales and revenue but

compensates utilities at the end of each year for reductions that result from programs that incentivize lower demand i.e. DR. Energy reductions below the baseline estimated energy demand will be repaid to the utility through higher future rates. Revenue adjustments can eliminate the long-run disincentive to reduce energy, but in the short-term, utilities will receive higher revenues from increasing electricity demand above and beyond the baseline.

Deregulation reduces regulatory power of utilities in order to create a freer market and induce competition amongst power generators and transmitters.⁶ Full deregulation eliminates state regulatory power and allows power generators and power transmitters to interact on the free market by buying and selling power at rates of their choosing. However, due to concerns about owners of transmission lines exerting monopoly power, deregulation has only been implemented partially. Deregulation in the United States has taken the form of deregulating the generation of power while leaving transmission companies under state regulation. Under this model, transmission and distribution lines are open to all power generators and consumers can choose their power supplier (see Appendix II for a diagram). Hereafter, unless otherwise specified this model of regulation will be referred to as deregulation even though transmission utilities are still fully regulated. Currently, 15 states are deregulated to some extent, while 7 states have suspended or cancelled deregulation efforts. Deregulation has been abandoned where the costs for existing power plants was so expensive to build that they would not have sufficient payback periods without an artificial increase in electricity rates. Taxing the sale of all electricity to recoup the costs of these old plants has been proposed as a solution to this transitional phase of deregulation. However, there has been a recent call for 're-regulation' in the United States as some analysts no longer believe deregulation is appropriate for the US electricity market.^{xxxviii}

⁶ "Generators" produce electricity while transmitters operate the electrical lines and metering infrastructure necessary to deliver the energy to the end user.

Section 3: Data Set and Descriptive Statistics

The primary source of data used in the analysis for this paper is the 2010 FERC Demand Response and Advanced Metering Survey which was published in early 2011.⁷ This paper draws on the demand response results for retail sector energy distributors for information about what entities are conducting demand response, the scale at which demand response is being conducted, and the structure of demand response programs. The survey was conducted in the first half of 2010 and asked demand response questions regarding the 2009 calendar year. It was sent to all 3,358 active utilities and other energy providing entities. Responses were voluntary and 52% of the entities responded, representing over 77% of electric consumers in the United States.^{xxxix} To check for selection bias, FERC chose 700 respondents and followed up with them until responses were received. There was no significant selection bias based on entity type or size. However, there are some states that have significantly lower reporting rates than others. The states with over 75% of customers unrepresented by utilities in the data were checked by searching the utilities' websites directly. The results from this analysis reveal that many of the utilities, particularly IOUs, had DR programs, but did not report them. These missing observations could impact regional control variables (see Appendix III for full analysis).

Data from sections 6, 7, and 8 of the FERC survey were merged to create the initial data set. Section 6 identifies the state and region of the observations, section 7 has information about the number and type of customers served, and section 8 provides demand response program specifics. Among other things, section 8 includes type of DR program, equipment eligible for program, customer sector targeted (i.e. residential), number of customers participating, and MW reductions attributed to program. The wholesale results included in section 9 of the survey were not included in

⁷ Data can be accessed at the FERC website: <http://www.ferc.gov/industries/electric/indus-act/demand-response/2010/survey.asp>

this analysis. Wholesale programs operate between states and are not subject to the same regulatory constraints as retail programs. Therefore, the analytical framework herein is not applicable to those programs.

To get information about utilities that did not respond to FERC's survey, this data was supplemented with the 2009 Energy Information Administration's (EIA), Form EIA-861 responses.⁸ This form must be filled out by all electricity distributors under the Federal Energy Administration Act (Public Law 93-175). The identification tags for respondents matched the FERC data set, but classes of customers were separated differently. FERC refers to customers as being residential, commercial/industrial, or other while EIA uses residential, commercial, and industrial. To combine the data sets, the numbers of commercial and industrial customers were combined in the EIA data. In some cases, variables from FERC's "other" category were dropped for consistency. The other category consisted primarily of agricultural customers. Only 109 programs (6.7% of all programs) were targeted at customers in the "other" category. However, due to this discrepancy in terminology, the analysis could not investigate the percentage of state commercial customers enrolled in demand response. Pricing data on the state level was retrieved from the EIA State Electricity Profiles 2008, which draws on 5 annual forms filed by electric power producers.⁹ Data on the status of decoupling was retrieved from the Institute for Electric Efficiency's 2010 report "State electric efficiency regulatory frameworks".¹⁰

Section 3.1: Types of Utilities

When referring to types of energy providers and types of DR programs, FERC's definitions will be used for consistency.^{x1}

⁸ Data can be accessed at the EIA website: <http://www.eia.doe.gov/cneaf/electricity/page/eia861.html>

⁹ Data can be accessed directly: http://www.eia.gov/cneaf/electricity/st_profiles/sep2008.pdf

¹⁰ Report can be accessed directly:

http://www.edisonfoundation.net/iee/issuebriefs/IEE_StateRegulatoryFrame_0710.pdf

Investor-Owned Utility (IOU)	A privately-owned electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return.
Publicly Owned Utility	Operated by municipalities, political subdivisions, and state or federal power agencies. Can be regulated, but are more autonomous than IOUs.
Rural Electric Cooperative or “Coop”	A utility in which the end-users hold membership stakes and own the utility. They serve their members as a nonprofit organization. Regulated and subject to utility requirements.

IOUs, public utilities, and coops are the 3 most common energy company structures in the United States. Public utilities account for the majority of reporting entities at 54%, while coops represent 26%, IOUs represent 8%, and the remaining 12% are other types of energy organizations. This analysis focuses solely on the three most common organizational structures and other demand response providers were dropped from this data set.¹¹ The dropped entities included curtailment service providers, which aggregate demand response and sell it to utilities and retail power marketers, which buy and sell energy on the wholesale market. The dropped entities do not serve electricity consumers or report to a regulator and have business models that are fundamentally different from those of an IOU, coop, or public utility. The dropped entities accounted for 8.49% of the utilities in the FERC dataset and 3.38% of the programs in the data set.

The largest utilities are IOUs, which serve over 650,000 customers on average while coops and public utilities are comparable in size averaging 30,000 and 51,000 customers respectively (see Figure III). Though the number of IOUs in the U.S. is small when compared to the number of public utilities, IOUs serve 71% of end-use consumers.^{xli} Public utilities are smaller than IOUs because they are restricted to their political jurisdiction and the majority of them are run by municipalities. Coops tend to be smaller than IOUs because the first cooperatives were established to provide electricity to

¹¹ Dropped 44 retail entities with DR, representing 7.6% of the entities and 3.5% of the DR programs in the FERC dataset.

rural areas where population density was low and economic returns were not high enough to attract private investment.

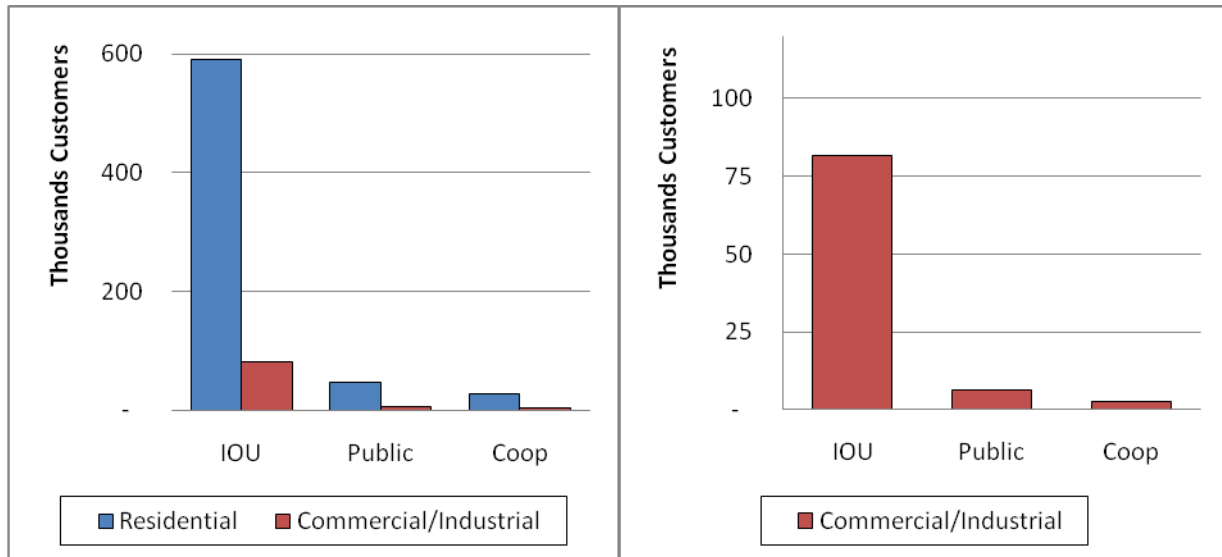


Figure III: Mean Customers by Utility Type

The majority of utilities conducting DR programs offer only one or two programs. Although the mean number of programs per entity is 3.1, large IOUs with millions of customers offered as many as 26 programs. Respondents were instructed to submit information for each type of demand response program and each class of consumer which used those programs, which explains how some entities have more than 10 programs. For example, a time-of-use program which serves both residential and commercial customers would have two observations. IOUs have the most programs per entity with a mean of 4.7, public utilities have a mean of 2.6 programs, and coops have a mean of 2.5 programs.

Section 3.2: Types of DR Programs

DR programs can be separated into incentive-based and price-based programs. Incentive programs compensate participants for enrolling in the program. After enrolling in the program,

participants must respond with demand reductions when called upon. From an economic theory perspective, incentive-based programs are essentially quantity instruments (with the exception of demand bidding); however, the term “incentive-based” will be used for consistency with industry terminology. Price programs are generally open to an entire class of customer (i.e. residential) and customers respond to pricing signals. If prices increase customers have the option to reduce their demand but are not required to. Despite the inherent uncertainty in price-based programs, a summary of 15 experiments showed a range of 6-20% reduction in electricity demand.^{xiii}

Incentive Program	Description
Direct Load Control (DLC)	System Operator remotely shuts down a customer’s equipment (e.g. air conditioner) on short notice. Primarily offered to small customers.
Interruptible Load	Enrollee’s entire electric flow is subject to interruption under contracts or tariffs. In exchange for electric bill reductions, customers agree to reduce load at the system operator’s will.
Emergency Demand Response	A demand response program that provides payments to customers for load reductions during an Emergency Demand Response Event.
Demand Bidding & Buy-Back	A program which allows a demand resource to offer load reductions at a price, or to identify how much load it is willing to curtail at a specific price.
Load as a Capacity Resource	Demand-side resources commit to pre-specified load reductions that are activated when system contingencies arise.
Price Program	Description
Time-of-Use (TOU)	A rate where usage electricity prices vary by time period, and where the time periods are typically longer than one hour per day. Time-of-use rates reflect the average cost of generating and delivering power during those time periods. The rates are known ahead of time.
Critical Peak Pricing (CPP)	Rate structure where prices increase during “system contingencies”, which are capped at specified number of days or hours per year.
Critical Peak Pricing with Load Control	Combines direct load control with critical peak pricing system. Rates increase during contingencies with an element of utility control.
Real-Time Pricing (RTP)	Rate structure in which price fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on a day or hour-ahead basis.
Peak Time Rebate	A rebate (per kWh) to customers that reduce energy use from a baseline during a specified period of time.

Time-of-use, direct load control, and interruptible load are the three most commonly offered types of DR programs (see Figure IV). Together they account for 85% of the DR programs in the United States. TOU programs require no infrastructure as long as the utility has a billing system that can handle different rates for different times of day. If meters are unable to detect the time of energy use, new meters must be installed. Interruptible and direct load control programs require switches to be installed for the utility to control electric loads, and in many cases the switches are installed in conjunction with a new appliance or water heater.

Figure IV: Type of DR Program by Utility Type

Note: # refers to the number of retail programs in the U.S. % Total refers to the percentage of programs of a certain type operated by that entity type (i.e. the percent of time-of-use programs operated by IOUs).

	Total		Coop		IOU		Public	
	#	%	#	% Total	#	% Total	#	% Total
Direct Load Control	497	30%	291	59%	110	22%	96	19%
Interruptible Load	257	16%	92	36%	126	49%	39	15%
Emergency DR	34	2%	1	3%	23	68%	10	29%
Demand Bidding	12	1%	1	8%	11	92%	0	0%
Capacity Resource	35	2%	16	46%	13	37%	6	17%
Incentive totals	835	51%	401	48%	283	34%	151	18%
Time of Use	631	39%	143	23%	247	39%	241	38%
Critical Peak Pricing	41	3%	14	34%	16	39%	11	27%
CPP w/ Control	30	2%	20	67%	5	17%	5	17%
Peak Time Rebate	14	1%	1	7%	9	64%	4	29%
Real Time Pricing	33	2%	2	6%	29	88%	2	6%
Price totals	749	46%	180	24%	306	41%	263	35%
Other	49	3%	24	49%	15	31%	10	20%
TOTALS	1633	100%	605	37%	604	37%	424	26%

IOUs coordinate a disproportionate percentage of the complicated structures such as real-time pricing and demand bidding. RTP requires extensive advanced metering infrastructure that can

track changes in rate on an hourly basis and preferably communicate them to the customer. Demand bidding programs have customers bid on the prices they are willing to take for demand reductions over their base line. Both of these programs would require dedicated capital and personnel to execute. Given the size of IOUs, it is logical that they would have more of these programs.

Demand response programs are disproportionately targeted at commercial and industrial customers. Only 12% of electric customers are non-residential, but 58% of DR programs are designed for them. This imbalance is particularly apparent for price-based programs, which target non-residential customers 68% of the time. Programs such as real-time price (94% non-residential) or demand bidding (83% non-residential), which require significant investment of resources by the utility are targeted to non-residential customers. On the other hand, DLC programs target commercial customers the least (22.7%). Most of these programs are operated by coops who give rebates to their members in exchange for control over their appliances.

The number of participants in demand response varies widely because programs can either be structured for residential participation on a large scale or for a few large industrial companies with a large electrical load. Although the mean number of customers in DR programs is over 5,000, the median number of customers is 62.5.¹² Running a naïve regression of a commercial customer-base binary variable on the number of customers enrolled, residential programs have ~12,000 more customers per program on average. This might explain why DLC programs have a mean of 11,500 customers enrolled while TOU programs have a mean of 2,600 customers enrolled.

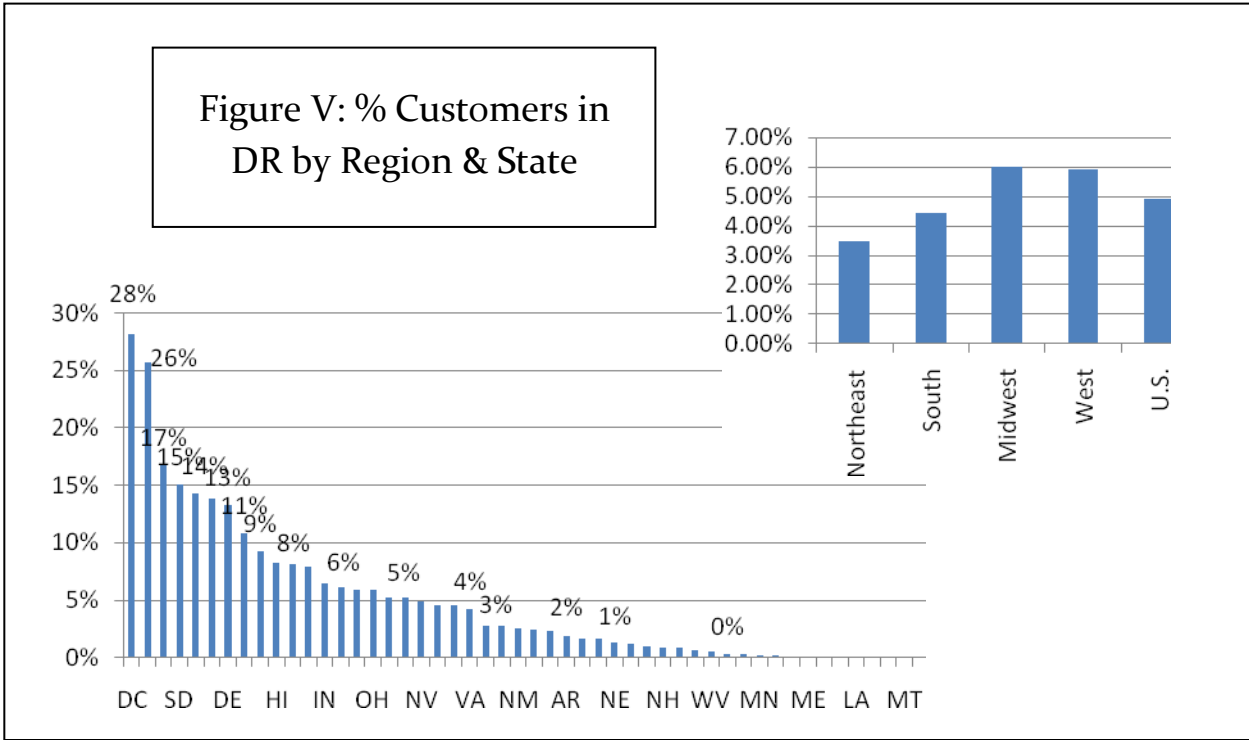
Further analysis of specific program types is difficult because there are a small number of observations for some program types. Additionally, some program types are very similar in structure to each other and a review of individual observations revealed that reporters might have had difficulty deciding which category of program to choose. For example, San Diego Gas & Electric

¹² All programs with “o” customers were omitted from customer number analysis. A value of “o” tends to indicate either a new program or a program without reliable information about the number of participants.

Company described one of their programs as a “capacity bidding program” but when given multiple-choice options chose “interruptible load” instead of either “load as a capacity resource” or “demand bidding & buy-back”. Though programs were mislabeled when deciding between types of incentive or price programs, there were no price-based programs labeled as incentive-based programs or vice versa. Therefore, my analysis focuses on the distinction between price and incentive-based programs.

States were divided into the Midwest, Northeast, South, and West regions. Borders between these regions were based on the work by Fell, Li, & Paul (2010) which analyzed how elasticity to electricity prices varies by region.^{xliii} A table detailing the regions is included in Appendix XX. It is important to note that although analysis of the United States electrical industry and demand response tends to segment the country into regions, there is wide variation at the state level. The percentage of all electric customers enrolled in a DR program exemplifies this variation. In the United States as a whole, 4.9% of customers are involved in DR. However, this number is calculated using exact numbers of customers in the United States from EIA, while the number of customers in DR is calculated using FERC survey results. These results count customers multiple times if they are enrolled in multiple programs.

When broken into geographic regions, the customer enrollment rates are fairly similar, ranging from 3.5% to 6.0%. However, there is a broad range of enrollment percentages at the state level with 28% in DC and less than 1% in Alaska and 13 other states (see Figure V). Similarly, the average number of programs per state is 33, but there are 239 in Wisconsin and only 1 in Alaska.



Section 3.3: Regulatory variables

This paper investigates the effects of deregulation and decoupling at the state level. As deregulation and decoupling are varied by region, the correlations between the two need to be understood. The Northeast is largely deregulated with the exceptions of Vermont and West Virginia. Both the South and Midwest have avoided market restructuring for the most part, while the West has cancelled decoupling in 4 states (Arizona, California, New Mexico, and Nevada). There are enough deregulated states for results to be reasonable and not skewed hugely by single states. However, when regional variables and deregulation are used in the same regression, some of the effects of deregulation might be picked up by the Northeast variable.

Decoupling & revenue adjustment present more of an interpretation problem because they are not as widespread as deregulation. These policies have only been adopted in 12 states, with California adopting both policies. Therefore outlier states are more likely to impact the mean result of decoupling or revenue adjustments. These policies are more evenly distributed across geographic

regions though and the correlation of these policies will not be as impacted by the addition of regional dummy variables.

Figure VI: Market Reform by Region

	Northeast	South	Midwest	West	Total
Deregulated	11	1	3	1	16
Cancelled	0	2	1	4	7
No Deregulation	2	9	10	7	28
Decoupling	3	0	1	2	6
Revenue Adj.	0	3	2	2	7
Return on Assets	10	9	11	9	39

Section 4: Conceptual Framework

This paper looks at three facets of demand response: (1) the DR implementation choice, (2) conditional on implementing a DR program, the type of program chosen, and (3) consumers’ participation in DR programs. First, the implementation analysis focuses on the decision of utilities of a given state to implement any demand response program. Here, there is no differentiation between the type or success of demand response programs. The outcome variable used to represent this is the percentage of utilities of a given state that choose to implement DR. Second, the program-choice analysis investigates which types of programs are chosen. Programs are split into price-based and incentive-based programs to see what factors make utilities more likely to adopt price-based rather than incentive-based programs. In addition, real-time-pricing programs are analyzed because they have fundamentally different infrastructural requirements than other DR programs. The three outcome variables for this level are whether the utility has any price based

program, the number of price based programs per utility, and the number of real-time-price programs per utility. Finally, the paper looks at the factors which affect participation once the program has been implemented. The outcome variable at this level is the percent of eligible customers enrolled in a demand response program. Together, these three levels of analysis give an overview of how demand response is being implemented by state and utility type in the United States.

The three strongest determinants of utility behavior are: (1) regulatory atmosphere, (2) entity structure, and (3) consumer characteristics.¹³ These factors affect decisions at each of the three levels described above. (1) Regulatory atmosphere can change compensation for utilities and pressure or mandate utilities to take action. For this analysis, deregulation, decoupling, and revenue adjustments were used to measure regulatory atmosphere. Though the initial model distinguished between state legislative action and regulatory action by the public utility commission, it is difficult to distinguish between legislative action and regulatory action because of the high correlation between the two variables. By including only a few policy variables, the analysis can look more closely at their effects while keeping in mind that correlations with deregulation or decoupling could reflect correlations with a broader regulatory atmosphere. (2) Entity structure affects the aggressiveness of firm, the time-horizon of decisions, and whether the firm is profit maximizing. Under the “property rights model” of firms, publicly held firms are less efficient than private firms because public firms do not feel the direct effects of financial losses and other inefficiencies.^{xliv} Although public firms might charge lower prices, this reflects a lack of profit maximizing motivation rather than increased efficiency.^{xlv} In the U.S. electricity market, private companies also lack profit maximizing incentives because the rates they can charge are regulated at the state level. Perhaps due to the effect of regulation, private firms have not proven more effective in the electric industry.

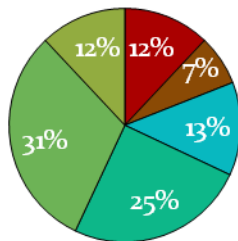
¹³ Though not included in this analysis, demand response decisions also depend on the existence of metering infrastructure and other technologies.

According to a meta-analysis by Hausman and Neufield (1991), 4 studies showed that public utilities were more efficient, 4 studies showed no significant difference, and only 2 studies showed that private utilities were more efficient. As IOUs are more heavily regulated than public utilities, this determines how the regulatory atmosphere affects the utility. The only measure for entity structure was whether the utility was an IOU, coop, or public utility. (3) Consumer characteristics such as environmental concern and price elasticity will affect how programs are received. Consumer characteristics can vary from state to state or within a single utility. Measurements of specific consumer traits are not available on a utility by utility basis, so the following analysis is based on the assumption that the nonrandom effects of consumer characteristics are not correlated with regulatory atmosphere or entity type.¹⁴ For information about consumer profiles on the national level, see Sidebar I. Though consumer profiles could vary between utilities, this paper assumes a uniform distribution.

Sidebar I: Profile of United States electricity consumers.

A 2010 survey by Accenture asked individuals from 17 countries about electricity management. Respondents were broken into six consumer profiles. The U.S. had the 2nd lowest percentage of “proactives” and “eco-rationals” and the 3rd highest concentration of “skeptics”, making the U.S. a unfriendly environment for DR.

U.S. Consumer Segments



- Proactives - Highest willingness act, not for environmental concerns though
- Ecorationals - Highest concern for environment, high social pressure, high willingness to change
- Cost Conscious - Highest sensitivity to savings, worried about complexity of program
- Pagmatics - High sensitivity to savings, ready to switch provider but worried about new technology
- Skeptics - Low acceptance of control, lowest trust
- Indifferent - Lowest willingness to act, program complexity is large deterrent

¹⁴ This might not be true if consumer characteristics are reflected in the regulatory body that they elect. For example, a more progressive consumer body might elect more progressive public utilities commissioners.

IMPLEMENTATION CHOICE

The wide variation of demand response across states in the same region indicates that there are state-specific characteristics which affect the implementation of demand response programs. Of the three determinants of DR adoption, regulatory atmosphere should have the largest impacts on a utility's decision to create a program. As every state has its own public utilities commission, the legislation varies widely by state. In particular, the deregulation of states in the last 10 years and the recent trend of revenue decoupling creates different incentive structures for utilities that are otherwise geographically and demographically similar. The influence of the other two determinants, entity structure and consumer characteristics, is secondary to the overarching regulatory structure. Specifically, deregulation and decoupling policies of the past decade have the potential to entirely alter electricity markets in a way that consumer belief in climate change could not.¹⁵

Although deregulation of electric utilities is a recent phenomenon, deregulation of utilities in other industries has increased the number of market entrants and shifted conventional models of doing business. In the railroad and trucking industries, deregulation sparked dramatic changes in company strategies.^{xlvi, xlvi} More recent studies have indicated that deregulation incentivizes companies to become more entrepreneurial, adopt new technology, and innovate more quickly.^{xlviii}^{xlix} In response to increased competition, companies either compete by lowering their prices or targeting a specific consumer segment.¹ Even within the electricity industry, research has shown that there is incentive for companies in deregulated markets to differentiate themselves by appearing environmentally friendly or offering “green” power.^{li} Portland General Electric initiated programs to restore salmon and expand its renewable energy portfolio with wind turbines. Demand response programs could provide such an opportunity for differentiation in deregulated states.

¹⁵ In addition to deregulation and decoupling, state regulators with an ISO must find common ground with all the states in the ISO's territory for programs like DR to succeed. If ISOs require a uniform system or coordination, this could explain some of the regional variation in demand response.

Despite the potential for utilities to use DR as a differentiator, deregulation has had a different effect on the electric industry than in the cases cited above. Using time series data, Sanyal and Cohen (2008) find that utilities in deregulated states drop their R&D budgets by 78.6% following deregulation.^{lii} The uncertainty of the restructuring process and threat of competition make firms reluctant to invest in long-term potential such as research. In regulated markets, regulators can promote demand response initiatives, but demand response programs will only be implemented if it is economically beneficial in fully deregulated markets. In regulated markets, 9 utility regulators in the U.S. have let utilities share in the costs savings that result from energy efficiency or demand response programs.^{liii} Other regulators provide guaranteed payback to utilities by providing an additional return on demand response infrastructure investments above the base return on capital.^{liv} I hypothesize that the threat of competition, uncertainty of how the market will respond to restructuring, and lack of regulatory pressure from deregulation will have a negative impact on the number of demand response programs. As cooperatives tend to operate in markets with a low population density, competition and uncertainty from deregulation might not be as pronounced. Additionally, coops maximize customer benefit rather than shareholder returns, so deregulation would not change their strategy as directly as the strategy of IOUs. I hypothesize the negative correlation between deregulation and the % of utilities in demand response will be stronger for IOUs than for cooperatives.¹⁶

Hypothesis 1: Deregulation has a negative correlation with the percentage of a state's utilities in demand response; this correlation is less pronounced for cooperatives.

The policy goal of decoupling is to eliminate the disincentive for utilities to reduce electricity consumption. Without decoupling, utilities face a short-run incentive to increase electricity demand

¹⁶ Hausman and Neufield also found that public utilities were more efficient prior to regulation. Their results showed that IOUs could have reduced costs by 21% if they were as efficient as public firms and took advantage of potential economies of scale.

in order to achieve higher revenues at their fixed revenue per kWh. Utilities are allowed to keep excess profits, but their profitability will be taken into account in their next rate case.¹⁷ Some utilities will avoid DR because consumers reduce their overall consumption in addition to shifting their consumption to off-peak hours, which would result in lower revenues for the utility.^{lv, lvi} Research by Moskovitz (1989) and Hirst & Blank (1993) explained how this compensation structure can seriously undermine demand response activities.^{lvii, lviii} Under this revenue model, utilities have incentive to promote DR programs for industrial companies which must run their electricity at some time even if not during peak hours. Residential DR programs might be avoided because many home appliances and air conditioning units will not use more electricity in off-peak hours to compensate for their demand response actions. This revenue model, along with the up-front cost of infrastructure, might explain the low levels of residential demand response potential in the United States. Decoupling has been proven to work in theoretical economic models. Brennan (2010) proved that in decoupled states it can be profitable for utilities to reduce demand because it reduces the use of infrastructure and delays expansion.^{lix} In some decoupled states, firms are willing to subsidize energy efficiency measures by giving rebates to customers because it reduces the cost of producing electricity.^{lx}

An alternative mechanism to decoupling, “lost revenue adjustments”, does not completely break the tie between revenue and sales but compensates utilities for their demand side management activities. Energy reductions below the baseline estimated energy demand will be repaid to the utility in the form of higher rates. Revenue adjustments can eliminate the disincentive to reduce energy, but utilities will still receive higher revenues from increasing electricity demand above and beyond the baseline. Despite the slight differences in the policies, the effect of both policies on the adoption of demand response programs should be similar. It should be noted that decoupling and revenue adjustments are most applicable to IOUs because coops and public utilities

¹⁷ Typically, utilities have control over when they set their next rate case and will do so at a strategically advantageous time.

should maximize the wellbeing of their customers and/or employees regardless of regulatory structure. However, cooperatives do face rate regulation in 17 states and have to redistribute excess profits to their consumers.^{lxi} If a coop faces demand losses from demand response so great that it would materially impact the economic returns to its members, deregulation could have a positive influence on the coop's decision to adopt DR.

Hypothesis 2: Decoupling is correlated with a higher percentage of IOUs in demand response.

This analysis focuses on the two hypotheses above and the effects of regulatory decisions; however, there are other factors which must be taken into account. The entity structure determinant might impact statewide adoption if certain entity types are more likely to adopt demand response programs. From state-to-state, the entity structure can be measured by an entity type's % share of total utilities i.e. the % of total utilities that are IOUs. For reasons described in the program level analysis, it is possible that higher concentrations of IOUs will be positively correlated with total % utilities in demand response.

The determinant of consumer characteristics could impact utilities across a state if they were more responsive to changes in price or had more appliances to put into an incentive-based program. A study by Fell, Li, and Paul (2010) showed that customers responded more to electric price signals in the South than in the Northeast by a significant amount.^{lxii} In the Northeast, demand is less elastic because fewer homes have air conditioning units and natural gas is a popular energy source. It is possible that price-based DR programs are established where customers can respond more to pricing signals. It is important to note that outlier states can cause the regional impacts to have significant values because there are a maximum of 51 observations. For example, both Kansas and Wisconsin have over 100 utilities in the state, but Wisconsin has 57 utilities with DR while Kansas has 9. Additionally, it should be noted that these regional boundaries are arbitrarily defined.

To test these hypotheses, I calculate the percentage of utilities with demand response programs by state. I then regress these percentages on deregulation, decoupling/revenue adjustment, and other controls. To control for entity structure, this process is repeated using the % of cooperatives, IOUs, and public utilities with DR programs. Other controls include a regional binary variable for the Midwest, West, South, and Northeast, the prices for different consumer classes, and the number of utilities in that state. The regional and price variables were included to capture some regional differences in consumer characteristics. The number of utilities is intrinsically a part of percentage of utilities in DR. However, during the testing phase of demand response, regulators might advocate for pilot programs in a few utilities but not all of them. In states with less than 10 utilities, a single pilot program accounts for a larger percentage of utilities than in a state with many utilities.

PROGRAM CHOICE

Once a utility has determined it will implement a demand response program, it must decide what type of program is best given both state-wide and consumer characteristics. Either a utility can adopt an incentive program where it retains total control over the timing and scale of response or a price program where response depends on consumer choice. In price programs, utilities rely on an indirect form of control where they must change prices to achieve their objectives. According to the FERC 2010 survey data, 46% of all programs operated by coops, IOUs, or public utilities are price based. However, plans for future DR programs indicate that incentive based programs will become increasingly popular. From 2010-2015, there are plans for 1732 incentive-based programs, but only 991 price-based programs.^{lxiii} The trend towards incentive programs contradicts the National Assessment conducted by FERC which reports that dynamic pricing programs are being underutilized.^{lxiv} The potential for DR in the U.S. ranges from 138,000 MW to 178,000 MW depending solely on whether price based programs enroll customers on an opt-in or opt-out basis. As these programs can make

such a large difference in demand response potential, it is important to know what factors make utilities more likely to implement them. This level of analysis looks at how utilities with demand response programs of any type choose which type of program to implement. Utilities without any type of demand response and utilities that were not an IOU, cooperative, or public utility were omitted from this level of analysis.

Although regulatory atmosphere will still impact program choices, the most important factor at this stage is the type of utility. For the regulatory atmosphere determinant, I expect that hypotheses 1 and 2 will hold for the decision to adopt price programs. I expect that deregulation will have a negative correlation with price programs, because utilities will not be compensated for their additional investment in infrastructure. Under regulation, utilities could make a rate case for why they need higher rates to compensate for advanced metering, but in deregulated markets this incentive disappears. As mentioned above, decoupling should have a positive relationship with the number of demand response programs overall, and therefore it should be positively correlated with the number of price-based programs. However, the relationship will not be as strong as with the percent of utilities in demand response, because demand reduction potential of price programs is not fully understood by utilities.¹⁸ Therefore, this uncertainty will weaken the disincentive to reduce demand.

Entity structure affects profit motive, how closely managers are monitored, and the adoption of new technologies. Therefore, entity structure is the dominant determinant in the process of selecting a type of DR program. Profit motive would incentivize utilities to innovate with demand response and choose price-based programs due to uncertain profitability of incentive-based programs and the ability to ask for higher fixed rates. Incentive-based programs have resulted in utilities paying more for their peak demand than they would have paid on the wholesale market;

¹⁸ As revealed by the missing observations for “megawatt potential” in the FERC survey.

therefore, profit-maximizing organizations might try price-based programs first. Work by Hollas and Stansell (1988) showed that IOUs behaved the most like profit maximizing firms, followed by coops and public utilities.^{lxv} For IOUs, either increasing energy sales or decreasing costs will benefit short-term revenues decoupled states, but will be adjusted for in the next rate case. Reducing costs will earn a profit in the short-term but will be accounted for in future rate cases. Coops are established as nonprofit organizations which serve the customers of an area that would not otherwise receive electricity. They distribute excess profits to their members, but there are no large shareholders or managerial incentives that promote profit maximization. Additionally, coops are subject to rate regulation in 17 states, further dampening their profit motive. Public utilities try to maximize both consumer benefits and workers' salaries.^{lxvi} To some extent, public firms will implement demand response in order to meet these objectives, but management does not directly benefit from economic success. Meyer (1975) found that public utilities set lower prices than they could which indicates a lack of profit motive and desire to depress rates for the benefit of consumers.^{lxvii} Based on their profit motive, IOUs have the strongest incentive to innovate with price-based programs.

For infrastructure-intensive programs, the profit maximizing motive for IOUs could distort incentives. In states without decoupling, IOUs are paid a fixed rate for sales which is set to compensate them for their investment in physical assets. Utilities that are required to invest in more infrastructure can apply to their regulator to be compensated for their expenditures. In a seminal 1962 study, Averch and Johnson showed that this can lead to overinvestment in infrastructure.^{lxviii} By inflating costs through infrastructure intensive projects, utilities can earn a higher rate for the electricity they produce. Based on these incentives, one would expect demand response programs operated by IOUs to be more capital intensive and promote the use of advanced meters. Real time price (RTP) programs, which require significant infrastructural improvements, might be a way for IOUs to increase infrastructure unnecessarily.

Utilities with strong profit motive tend to have more intense monitoring and are more likely to adopt price programs. Monitoring is often seen as a way to get managers to accept more risk for a given level of compensation.^{lxi} The theory says that more closely monitored agents will not be held accountable for results they did not have control over. In IOUs, stockholders elect a board of directors, which in turn appoints managers. Managers face scrutiny at regular board meetings, by investors, and by the public utilities commission. IOU managers' compensation can be tied to performance and reviewed by these monitoring bodies. Methods of motivating IOU managers are outlined by Rajagopalan (1997), who advocates for detailed incentive structures in alignment with firm objectives.^{lxx} In contrast, cooperatives' managers are elected directly by the membership (customers) of the cooperative. Members have little incentive to monitor managers because their membership cannot be resold, so effective monitoring will only affect a small portion of their electricity bills and cannot increase the value of their membership status. Also, each member gets one vote regardless of electrical consumption, which disincentivizes the largest customers who have the most to gain from monitoring. Therefore, managers face less risk if they make a poor decision.^{lxxi} Managers at public firms are appointed by elected officials,

Finally, entity structure affects the decision to enroll in price programs because different utility types are more open to new technologies. IOUs tend to adopt technology more quickly than public utilities or coops. Although Sommers (1980) finds that large firm size speeds technology transfer, Rose & Joskow (1990) believe this greatly understates the importance of entity structuring because the two are serially correlated.^{lxxii, lxxiii} Peltzman (1971) provides further evidence of entity structure impacting technology adoption beyond their number of customers. His analysis concludes that public firms acted more slowly and with more precaution than private utilities due to bureaucratic barriers and reluctance to upset voters.^{lxxiv} Technology adoption by cooperatives has not been researched thoroughly; however, evidence suggests that they are less likely to initiate R&D.

Although now dated, a 1987 report revealed that only 32% of coops and 37% of public utilities were members of the Electric Power Research Institute (EPRI), while 73% of IOUs were members. EPRI conducts research and development for the electricity sector and participation is an indicator of openness to and support of new technology.

Hypothesis 3: IOUs are most likely to implement price-based programs, followed by cooperatives, and then public utilities.

Hypothesis 4: The gap between IOU and other entity types in the adoption of price-based programs will be more pronounced for RTP programs.

The consumer characteristic determinants might impact price program decisions through the % commercial customers & residential customers' environmental beliefs. Price programs are more popularly implemented for the commercial sector because with fewer clients the metering infrastructure is a smaller up front expense. Only 49% of incentive programs are offered to commercial customers while 68% of price programs are targeted to commercial customers. Utilities with more commercial customers might be more likely to choose price based programs. For residential price based programs, more environmentally-conscious consumer bases would have a greater demand response potential. Environmental enthusiasts might make price-based demand response into a competition as some have done with hybrid cars and "hyper-miling".^{lxxv} However, the effect of consumer preferences cannot be measured by the data used in this analysis.

For the program level analysis, I use one observation per utility. I use three outcome variables: a binary variable for whether a utility has a price based program, the number of price based programs, and the number of RTP programs. The number of RTP programs essentially functions as a binary variable because of the 29 programs, 25 have only one program. These variables are regressed on deregulation, decoupling/revenue adjustment, entity type, the state's average electricity prices, the number of customers the utility serves, the % of customers that are residential

customers, and a regional control. The binary price program results are obtained using both basic regressions and probit regressions. The number of price programs is analyzed with Poisson regressions in addition to basic regressions.

ENROLLMENT CHOICE

Utility-wide participation rates are the best measure of successful interaction between utilities and their customers for the FERC survey. Despite the importance of DR scale (in terms of MW) to the security of electric supply, there is poor reporting of both the potential megawatt reductions and actual megawatt reductions of DR programs. Only 34% of the price-based programs in the sample have observations for potential megawatt reductions and though 90% of incentive-based programs reported some value, the comments submitted with the survey indicate that there was some confusion about how to report “potential” megawatt reductions. The lack of price-based information is an indication that (1) programs are not being modeled extensively before being implemented and (2) there is not a wide-spread industry standard for calculating time-based program potential. Therefore, the rate of participation by eligible customers is the best reflection of success across both price-based and incentive-based programs.

When considering participation rates, the key determinants will be entity type and consumer characteristics. Regulatory atmosphere could pressure utilities into creating DR programs and the direction of the effects in hypothesis 1 and 2 still hold here, but these are secondary to the relationship between consumers and their utility.

Entity type impacts the incentives for utilities to create positive relationships with their customers and their ability to do so. Recent work by Kwoka (2005) indicates that public firms are more successful than IOUs at the distribution of electricity, where qualitative outcomes i.e. customer service are important.^{lxxvi} Kwoka proposes that IOUs can operate more efficiently than a public firm when there is no difference in the quality of the end product, such as the generation of

electricity. However, when customer service is involved, private companies have incentives to cut corners and provide lower quality service. IOUs are granted monopoly distribution rights even in deregulated states and have limited incentive to improve customer service. On the other side of the scale, cooperatives are particularly effective at building relationships with their customers. Many cooperatives explicitly mention serving their members as their mission. For example, compare the mission of New Hampshire Electric Co-op with the corporate vision of Florida Power and Light (an IOU):^{lxxvii, lxxviii}



Approximately 72% of coops in the U.S. are members of “Touchstone Energy Cooperatives”, a branding organization developed by the National Rural Electric Cooperative Association.

Touchstone explicitly incorporates “concern for community” into its principles and was created to “represent the relationship between the [coops] and their consumer-members and the communities they serve”.^{lxxix} According to the Touchstone website, its members score an average of 81 on the ACSI customer satisfaction index, much higher than the industry average 74.^{lxxx} Heffner and Goldman (2001) note that cooperatives can leverage their relationships with consumers into more effective and less costly DR programs.^{lxxxi} They cite Wabash Valley Power Association as a cooperative which runs a program with no advanced metering infrastructure by developing a multi-channel communication system on an “honor system” basis. The coop establishes curtailment strategies with customers up front and checks demand response with pseudo-accurate analytics i.e. baseline methods but do not

have real time data to ensure compliance. This shows that the trust between coops and their customers is transferable to DR and feasibly can be leveraged into higher participation rates.^{lxxxii}

Consumer characteristics which might increase participation rates include: concern about the environment, elasticity to electricity prices, and familiarity with technology. These factors cannot be measured by my data set apart from using regional variables. Another factor to consider for participation percentage is the number of customers served by a utility. Smaller consumer bases would be easier to inform about DR programs through direct outreach and information would spread more rapidly in informal settings. However, the correlation with entity type makes analysis of regression outcomes difficult. Cooperatives have better relationships with their customers and serve smaller populations, so it is difficult to determine what is causing correlations.

Hypothesis 5: Cooperatives will be strongly correlated with higher participation rates.

As mentioned above, the outcome variable most appropriate for success is the percent of eligible customers enrolled in a program. This analysis includes each program as a separate observation. Double counting is possible when customers are allowed to enroll in multiple programs. For example, there are 12 utilities with over 100% of customers in demand response, but these are smaller utilities with a mean of 11,984 customers while the average for all observations is 186,791 customers. This would bias results if the utilities that double counted were non-random. Entity type and regulatory variables are included along with controls for region, electricity price, % of customers that are commercial or residential, and the total number of customers.

Section 5: Results

IMPLEMENTATION CHOICE

Hypothesis 1: Deregulation has a negative correlation with the percentage of a state's utilities in demand response; this correlation is less pronounced for cooperatives.

Deregulation has a negative correlation with the % of the total number of utilities with DR programs, but the effect is not always significant. Deregulation is correlated with a 5.6-7.6% decrease in utilities participating in DR until regional variables and price level variables are added. A high percentage of Midwest utilities operate DR programs, particularly in Wisconsin. As deregulation is less common in the Midwest (correlation=-.1318) than the Northeast, it is possible the regional variables are watering down the negative effects of deregulation. Although deregulation is statistically insignificant once regional variables are added, the magnitude of the parameter remains constant. Regardless, deregulation does not seem to spark innovation in demand response for the U.S. electricity market. Assuming that regional differences do not have a causal relationship with the percent of utilities in demand response, deregulation does have a negative correlation with utility participation in DR.

The negative correlation between demand response and deregulation could indicate that demand response programs prevent the implementation of deregulation. Deregulation creates pricing variations through competition, so time-of-use programs can be seen as an alternative solution to the lack of price variability in regulated markets. Utilities which want to prevent deregulation and the ensuing competition in their market could bargain with their regulator to delay deregulation if the utility created a TOU program. This effect is checked by creating a variable which measures the percentage of all utilities within a state with at least one TOU program. Deregulation is regressed on this variable to see if there is a correlation between TOU program concentration and a lack of deregulation. Although the correlation is negative, the effect is nonsignificant in regressions (see Appendix IX). IOUs might have the most sway over regulators because they serve a larger customer base, so the same regressions are run using the percent of IOUs with TOU. Using IOUs instead of all utilities, the negative correlation is stronger, but still insignificant. Therefore the negative correlation between deregulation and demand response in the regressions shown in

Appendix VI cannot be explained solely by TOU demand response programs as a tactic to prevent deregulation.

States which have implemented or initiated deregulation before cancelling it are positively, though insignificantly, correlated with higher demand response activity than in baseline states without any sort of deregulation. As this regression is run on all utilities within the state, it can be interpreted as a check or control for state progressiveness. States that have cancelled deregulation are progressive enough with their energy policy to have considered market reform before deciding that it was not advantageous. If there was a quality about the states which would consider reform which impacted utility adoption of DR, it would be picked up in part by the states which have cancelled deregulation. Therefore, it is more likely that the progressiveness of energy policy itself is not correlated with lower demand response and the effect measured in deregulated states has more to do with the effects of deregulation itself than state-wide characteristics.¹⁹

When looking at the percentage of IOUs in a state with DR, the negative correlation with deregulation holds for regressions without controls. However, once the number of IOUs in the state is corrected for, the correlation diminishes. A potential explanation for the importance of the number of utilities in a state is that regulators want at least one IOU to test demand response, but are unlikely to approve multiple programs for cost recovery measures if demand response has not proven its effectiveness. Even under deregulation of power generators, regulators still have oversight of the transmission utilities and could require them to implement demand response. Also, there is a correlation of .46 between the number of IOUs in a state and deregulation. If IOUs lobby for deregulation, then the # of IOUs could impact whether or not a state deregulates. This might be the case if IOUs see deregulation as an opportunity to make more money because they believe they will be able to maintain their monopoly status and charge higher rates. If states with more IOUs are

¹⁹ This would not be the case if, for example, a liberal government repealed deregulation that was put in place by a conservative government.

deregulated, it is difficult to make any causal links or even accurately interpret the correlations from the regressions. Regardless of causality, it is clear that in deregulated states, IOUs have an average 20.5% lower participation rate.

Unexpectedly, the percent of coops with demand response is positively correlated with deregulation. However, like the total % of utilities in demand response outcome, the significance diminishes when control variables are added. As coops should be operating in the best interest of their members/customers, they should only differ in strategy based on regional knowledge or customer preferences. These correlations might indicate that under deregulation, cooperatives are concerned about other energy companies eroding their customer bases and are willing to offer them rebates in the form of incentive-based programs. Dupont (1998) argues that in deregulated markets, members of cooperatives are likely to leave the cooperative for lower electricity rates. Further, Dupont believes that to keep customers, coops must create stronger relationships with their consumers i.e. demand response programs. However, because most cooperatives operate in markets with low population density, they are unlikely to face as much competition as IOUs. Therefore, this correlation more likely underscores the small number of observations when looking at adoption on the state level.^{lxxxiii} With only 51 observations, phantom causality and correlation are of great concern. It is also important to note that the magnitude of the deregulation parameter decreases as more controls are added.

For the % of public utilities with demand response, deregulation does not have a significant effect regardless of the control variables and the magnitude of the effect is much smaller than it is for IOUs or coops. This is expected, because public utility incentive structure is not heavily impacted by deregulation. There is a correlation between public utility DR and the price of residential electricity. For each additional cent/kWh in residential prices, public utilities are 5.2% more likely to have a demand response program. Voter support is a major factor in the utility incentive structure,

so one would expect them to face more intense pressure for alternative pricing schemes when prices were higher. In areas with high residential prices, customers could lobby for lower prices and public utilities are more willing to experiment with demand response in the hopes of decreasing prices.

Overall, hypothesis 1 seems to have some weight to it. Although the results were not robust to control variables, deregulation has a negative correlation with utility participation in demand response. This occurred under partial deregulation and under full deregulation the effects might be more pronounced. As might be expected, cancelling or rescinding deregulation has no significant effect on demand response relative to states which never implemented demand response. The negative correlation between deregulation and demand response participation was most pronounced for IOUs, which are the most heavily regulated type of utility. The concurrence of these results might imply that deregulation affects demand response negatively, but no causality can be proven.

Hypothesis 2: Decoupling is correlated with a higher percentage of IOUs in demand response.

Across all utility types, decoupling is insignificantly related to utility participation in demand response. For cooperatives the correlation is slightly positive, while the effect for public utilities and IOUs is slightly negative. However, the results only exceed the 10% level of significance for public utilities and this correlation is less significant once control variables are added. There is no significance for IOUs which were hypothesized to have a positive correlation.

There are three reasons why IOUs might not be more likely to implement demand response once revenues no longer depend on electricity sales:

1. Non-uniform application of policy: Approval of decoupling is required in some states, and the alternative revenue models might not apply to all IOUs. The majority of decoupling and revenue adjustment structures have only been approved for 1 or 2 utilities within the state. If the majority of IOUs in the state are still incentivized to increase demand for electricity, demand response participation would not be positively correlated with decoupling.

2. Time to implement: As most decoupling programs were implemented in the past 5-10 years, the effects of these compensation changes might not be felt yet. Demand response can be planned out 3 years or more in advance. Additionally, IOUs under new revenue structures might prioritize other initiatives over demand response. For example, energy efficiency measures such as weatherization of houses are increasing in popularity. In a firm with limited resources, demand response might be put on hold.
3. Uncertain benefits and market: IOUs are not convinced about the benefits of demand response. The fear of uncertainty might be exacerbated by a changing revenue structure.

Although this analysis does not find any significance between revenue model and demand response participation, further analysis is necessary before strong conclusions are drawn.

PROGRAM CHOICE

The program type analysis uses the results of regressions on both a binary measure of whether a utility operated any price-based programs and the number of price-based programs that were operated. Both measurements show that IOUs are significantly more likely to implement price based programs than cooperatives. However, public programs are not always significantly different from IOUs. It appears that hypothesis 3 correctly predicts the behavior of IOUs but is incorrect with regard to public utilities, which are more likely to implement price programs than expected. For the binary decision to implement price programs, coops are between 23% and 29% less likely than IOUs to have a price program.

Though the primary takeaway is that coops are less likely to implement DR than other types of utilities, these results can be applied to other hypotheses as well. With regard to hypothesis 1, there is wide variation in the magnitude of the deregulation coefficient. For IOUs and public utilities, deregulation is negatively correlated with the decision to implement price programs, but

the correlation is positive for cooperatives. While the correlation between the binary measure of whether an IOU has price-based DR and deregulation is insignificant, it is significant when the outcome variable is the number of price programs instead of a binary variable. This could imply that utilities tend to implement at least one type of price program with equal frequency regardless of deregulation, but that deregulation negatively affects the quantity of price programs. Poisson regressions of the number of price programs on deregulation showed negative correlations in IOUs ranging from -.53 to -.59. This means that deregulation is correlated with .53 to .59 fewer price programs per IOU. This provides further support for the theory that regulatory bodies are able to pressure IOUs into adopting technology and adopting more risky technologies i.e. price-based programs. If the negative effects of deregulation on DR are more pronounced for price programs, this could mean that more incentive programs would be put in place without deregulation. Utilities might need more pressure and incentive to create price programs than they receive under deregulation.

For cooperatives, deregulation is again correlated with an increase in demand response adoption. Deregulated cooperatives are 3.6-6.3% more likely to have a price based program than regulated cooperatives. Using binary measures for price program decisions, the results are significant until controls for decoupling, customer type (i.e. residential), and region were added. However, the magnitude of the effect remains constant despite the change in significance. For regressions using the number of price programs as an outcome variable, the significance of these correlations is robust to control variables.

Unlike the analysis at the state level, the regressions on the number of price programs show a significant positive correlation between alternative revenue structures and DR for IOUs. Decoupled or revenue adjusted IOUs have on average 0.84 to 1.14 more programs than IOUs in states without price reform. Utilities which are compensated based on the volume of energy they sell might be

reluctant to implement price programs because the quantity of demand reductions is not in their control. If one of these utilities sets the price of electricity too high and customers respond by dramatically reducing demand, it could have significant impacts on their profits.

Hypothesis 3: IOUs are most likely to implement price-based programs, followed by cooperatives, and then public utilities.

As hypothesized, cooperatives are significantly less likely to have price programs than IOUs; however, public utilities are more likely than coops to have price-based DR. Using both binary decisions and number of programs chosen, cooperatives have significantly less price-based DR than IOUs. If the effect was only significant for the number of programs but was insignificant using binary measures, cooperatives might just have too few customers to merit a large number of programs. However, the binary results show that cooperatives are 22-29% less likely than IOUs to have any type of price-based DR. The number of customers was also controlled for, so these effects are being driven by something other than the scale of the utility.

The literature suggests that IOUs are more innovative with technology and therefore more likely to use price-based DR. These results are consistent with this hypothesis. Perhaps closer monitoring by regulatory bodies and shareholders encourages IOUs to experiment with these price programs. Or perhaps their profit motive makes them prefer programs that do not pay customers up front and cannot lose money; they might be averse to incentive programs after the demand response failures of the early 1990s. Regardless of the motivation behind their adoption of price programs, IOUs have clearly taken the lead with riskier programs such as TOU.

Residential prices are highly positively correlated with more price programs. This could be caused by increased pressure on the utility from higher residential prices, which could come from their regulators or the customers themselves. However, it is also possible that price programs tend to increase the average price of electricity even though the price of off-peak electricity declines. Price

programs were negatively correlated with industrial prices which might indicate that industrial programs are cost effective regardless of price while residential programs require more incentive. Utilities can build stronger demand response relationships with commercial and industrial customers, because they have larger capacities than residential customers. The management of these programs requires fewer personnel and other operational costs. Therefore, utilities might engage in these programs even if prices for commercial customers are low. Again, there is the possibility that demand response programs create lower prices instead of the other way around.

Hypothesis 4: The gap between IOU and other entity types in the adoption of price-based programs will be more pronounced for RTP programs²⁰.

As hypothesized, IOUs were highly correlated with more RTP programs. The model showed that coops had between .17 and .30 fewer programs per utility than IOUs while public utilities had between .17 and .29 fewer programs per utility. These results were all significant at the 99% confidence level. Looking at the raw data, there are 25 IOUs, 2 coops, and 2 public utilities with RTP programs. When analyzing these regressions, I was looking for control variables which might indicate that something other than entity type was causing this trend. It could have been the case that only utilities with a minimum number of customers or a minimum price of electricity implemented RTP. Although the number of customers was positively correlated with RTP, the inclusion of this variable did not impact the significance of entity type. Perhaps due to the Averch Johnson affect or general incentives to be more innovative, IOUs are most likely to choose programs which require advanced metering.

Again, using RTP as the outcome variable, deregulation was significantly negatively correlated with demand response. However, this only applies to IOUs and RTP as a whole did not

²⁰ According to the FERC results, from the 2008 to the 2010 survey, the number of entities with at least one RTP program declined from 85 to 19. FERC notes that in the 2008 survey, respondents could report multiple program types for the same program, which could have caused this decline.

have a significant correlation with deregulation. Decoupling had a significant, positive correlation overall. It seems that this only applies to IOU when the effect is broken out by entity type.

ENROLLMENT CHOICE

Hypothesis 5: Cooperatives will be strongly correlated with higher participation rates.

Cooperatives were significantly positively correlated with higher utility-wide participation rates. In fact, the binary variable for coops was the only variable that was consistently significant at the 95% confidence level in the regressions apart from regional variables. The regressions showed that coops had 12-15% higher participation rates when compared to IOUs. Although the specific causal link is uncertain, it is clear that IOUs and even public utilities can learn something from cooperatives. As the results of this were measured for all types of customers, this could skew results towards entity types catering mainly to residential customers. In the U.S. 87% of customers are residential customers so the results of this regression should be applied to residential customers. Coops seem to have programs that are particularly popular with their residential customer base.

Based on a search of coop websites, many of these programs are rebates direct load control programs. Customers are able to get cash up front when they install an appliance i.e. an air conditioner and in exchange the coop is able to put a control device in the appliance. This might call into question whether the coops are correlated with higher demand response, or whether it is the choice of direct control programs. The final regression includes a dummy variable for the number of DLC programs operated by the utility. Although less of the increase in participation rates is attributable to coops, there is still a significant positive correlation between coops and enrollment. It seems that even given the type of programs employed by coops, they have some way of getting their customers involved in programs that is not utilized by public utilities or IOUs.

An alternative explanation of high enrollment rates is that cooperatives operate programs that maximize consumer benefit rather than profits. If cooperatives exist to serve their members,

they might offer higher rebates to customers than an IOU would. Considering that profits of cooperatives are redistributed to members eventually, higher than optimal rebates merely redistributes the profits to those who are providing a service to the coop by altering their demand. The correlations seen in this analysis are probably caused by a combination of coops having better customer relationships and less profit motive.

Section 6: Conclusion

This analysis of the FERC data set offers potential explanations about the larger trends in U.S. demand response. The econometric approach herein cannot prove causality but found some interesting correlations that can be used for future study. The most important findings of this study are: deregulation seems to have a negative or neutral impact on demand response, IOUs are the most likely of the utility types to implement price-based programs, and coops have high enrollment rates.

Deregulation has been touted in many industries as a catalyst for change and revolution. However, in the case of demand response, utilities are less likely to create DR programs or experiment with price-based programs. Restructuring markets even through partial deregulation might cause enough uncertainty to prevent utilities from risking resources on demand response initiatives. Some economists argue that deregulated markets will reach efficient solutions and that demand response will only be implemented where it is economically viable. However, if demand response benefits society as a whole without being profitable to utilities, deregulation may cause utilities to provide suboptimal amounts of demand response.^{lxxxiv} The energy reductions from DR can be 2 to 3 times more expensive than the equivalent cost of energy on the wholesale market.^{lxxxv} However, when societal benefits are included, DR has a cost benefit ratio of 2.1-2.3.^{lxxxvi} If public

utilities commissions lose some of their leverage over utilities in deregulation, states could be missing out on the positive externalities of DR.

Certainly, states should not prioritize demand response over full deregulation and long term competition. However, public utilities commissions should have plans for how they can stimulate DR adoption once markets are deregulated. Encouraging DR in a deregulated environment could take the form of retaining partial regulation of utilities or reducing the uncertainty of the deregulation process. To reduce the uncertainty of restructured markets, utilities commissions can communicate openly about their process. Regulatory commissions can also provide information and educational support about the process.

Price-based programs like time-of-use programs help smooth demand consistently without restricting the utility to a certain number of days per year or cost per use. Due to the uncertain reductions from price programs, these can be used in conjunction with incentive programs with guaranteed reductions. Based on this analysis, IOUs are more likely to establish programs with price signals rather than direct control over their customers. IOUs are less likely to implement price programs in deregulated states which might indicate that regulatory pressure is necessary to incentivize price programs. If so, regulators could expand their influence and provide support to coops to get them to start price programs. Coops can expand beyond their direct load control programs and continue to leverage their close relationships with their members. There seems to be an untapped potential for cooperatives to engage in demand response as coops have already seen participation rates 66% higher than those of non-coops for time-of-use programs.²¹ A large proportion of underutilized demand response lies in price-based programs; therefore, cooperatives and public utilities must start implementing more price based programs if the United States is going to improve upon the “business-as-usual” projections for demand response. By cultivating a better

²¹ The 128 programs operated by cooperatives have a mean of 4.0% participation while the other 365 programs have a mean of 2.4% participation.

understanding of why IOUs are choosing to use price-programs, regulators can encourage similar behavior from coops.

Using percent participation as an indicator of successful demand response, coops are the most successful utilities. Even when the size of cooperatives is accounted for, they have significantly higher enrollment rates than either IOUs or public utilities. A portion of this can probably be attributed to better customer relationships and communication. However, a single technique could contribute largely to coop success i.e. including demand response applications with consumer electric bills. Case studies on the marketing and outreach efforts of demand response could provide regulators and IOUs insight into the successes of coops. A cost benefit analysis of coop programs could reveal if coops are essentially subsidizing programs because they lack a profit motive. This analysis could also be used to see how cost benefit ratios vary depending on coop characteristics.

Although this paper focuses on demand response, the results can be applied to the electricity market in general. Variation in success between entity types showed that cooperatives have better success in programs that require participation from and engagement with their customers. Their nonprofit status and focus on a smaller region might make them more trustworthy, and this can be used to their benefit. Coops can utilize this advantage by conducting programs which require customer interaction such as home energy audits and weatherization. Public utilities were less successful at enrolling customers than coops, which indicates that regionality and small size are not the only factors contributing to cooperative success. IOUs and public utilities alike can work to build consumer trust and communication.

The results with regard to deregulation support the idea that the effects of market liberalization are not uniform across all industries. In particular, deregulation does not necessarily spark innovation or might favor innovation in certain technologies. These results were obtained for states facing partial deregulation, and utilities could innovate even more slowly under full

deregulation. States should think through how deregulation will affect technology and the implementation of a smart grid. As new technologies in addition to demand response regulated states will have more control over how these are implemented. Deregulation is intended to reduce electricity prices by increasing competition, but slower technology adoption could put upward pressure on prices in the long-run. Coordinating technology adoption across utilities will be crucial as the smart grid movement continues to gain momentum.

The correlations from this research have implications beyond demand response if they hold for other smart grid technology. These results, particularly the negative relationship between deregulation and technology adoption should be tested for how universally they apply. Further research on demand response could look more closely at the consumer characteristics which affect program success. By using census data and GIS, regional analysis of customer acceptance is possible. This could either be done by looking at geographic, socioeconomic, or attitude differences of enrollees in the same program or at a more regional level.

Although this paper reveals negative correlations between deregulation and demand response, the causality and linkages are still poorly understood. To determine why this is the case, interviews of utility managers going through or facing impending deregulation would reveal what their priorities and concerns are in an unstable market. The negative correlation indicates that both utilities manager and regulators can improve DR efforts in deregulated markets, but the barriers to implementation are still unclear. By understanding the impact of deregulation on firm behavior in a more detailed level regulators can be more aware of the impact they are having.

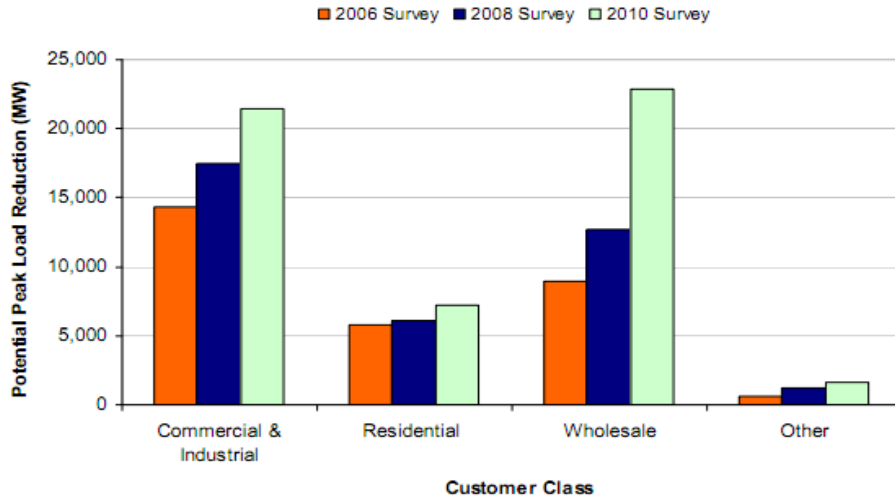
More information about the effect of mandatory or opt-out versus opt-in programs would help utilities make decisions in how to enroll their customers. Although many utilities responded to the FERC survey as having “mandatory” programs, almost all of them meant that participation was mandatory once enrolled. There seem to be very few programs that are actually mandatory and only

28 were labeled “opt-out”. Utilities and public utilities commissioners in regulated environments can propose more mandatory programs because utilities do not need to worry about customers switching to other service providers.

As the smart grid continues to roll out across the United States, we can look to the adoption of demand response to learn about how utilities make decisions. The correlations between innovativeness and regulatory atmosphere, entity type, and consumer characteristics foreshadow future barriers to smart grid implementation. Deregulation might stifle innovation and risky investment by utilities. When looking for utilities to implement technologies, IOUs might be more receptive as they are more willing to accept the risk of price-based programs. Finally, cooperatives have effective methods of communication and engagement with their customers. Other utilities can learn how to reach out to their customer base by mimicking the regionality and customer-focused messaging of cooperatives. A holistic perspective of how utilities adopt new ideas can improve energy efficiency and help the U.S. electricity industry through the impending smart grid revolution.

Appendix I

Figure 4.7. Reported potential peak load reduction by customer class in 2006, 2008 and 2010 FERC Surveys



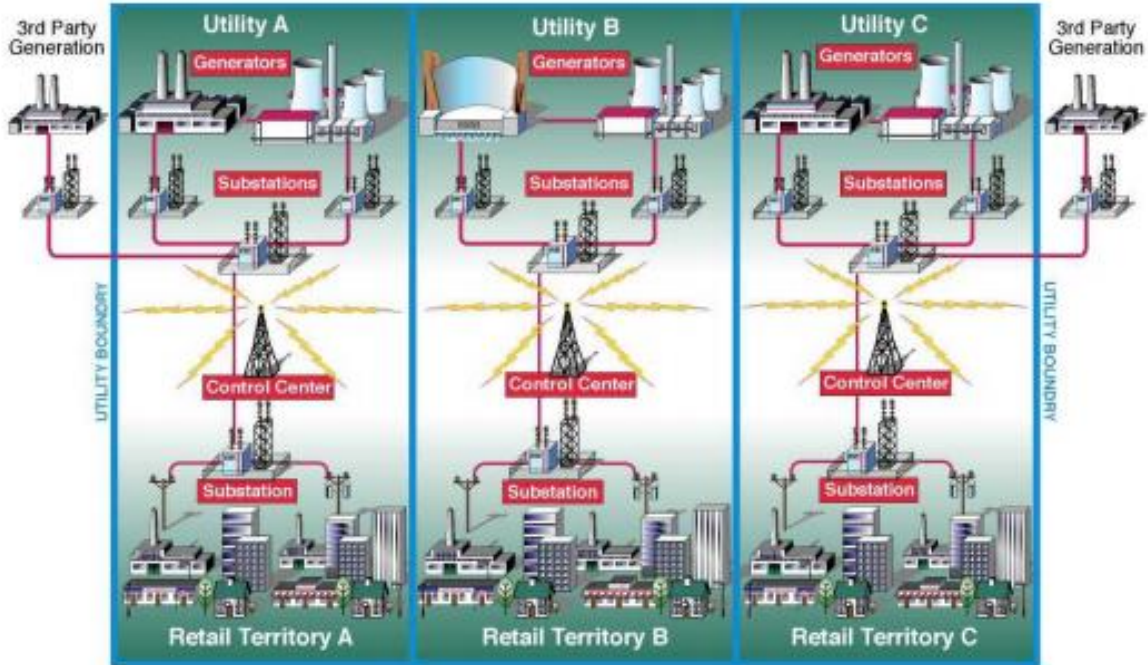
Appendix II: States by Region

Fell, Li, and Paul ^{lxxxvii}			
Northeast	South	Midwest	West
MA	FL	IL	AZ
NJ	GA	IN	CA
NY	MD	MI	CO
PA	SC	MN	OR
	TX	MO	WA
	VA	OH	
		WI	

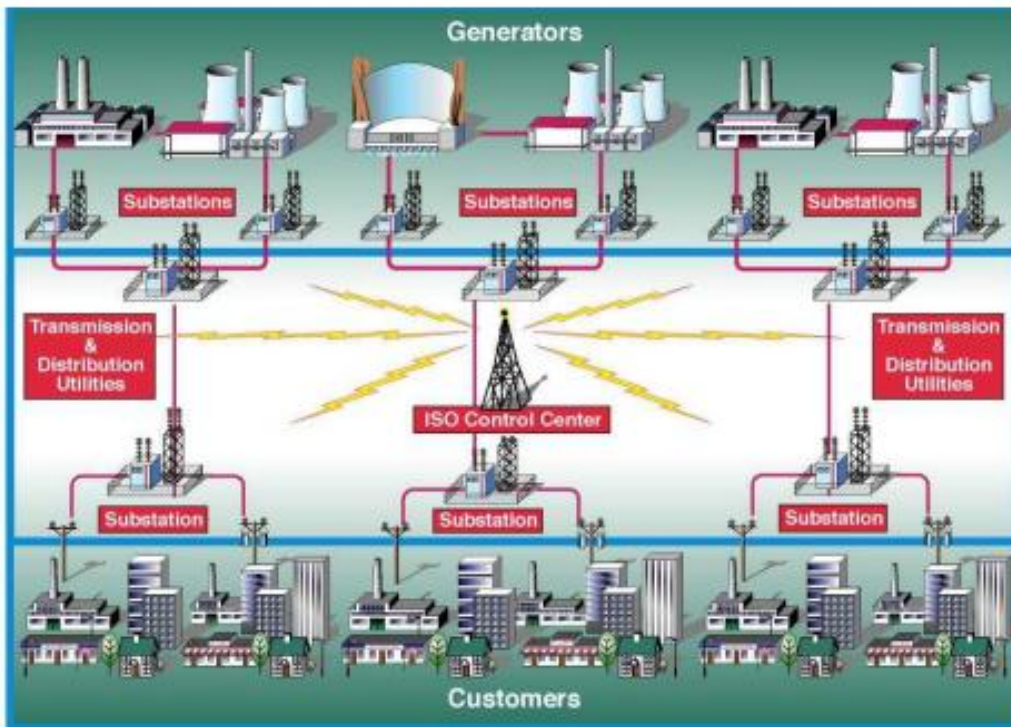
Expanded to all states			
Northeast	South	Midwest	West
CT	AL	IA	AK
DC	AR	IL	AZ
DE	FL	IN	CA
MA	GA	KS	CO
MD	KY	MI	HI
ME	LA	MN	ID
NH	MS	MO	NM
NJ	NC	MT	NV
NY	SC	ND	OR
PA	TN	NE	UT
RI	TX	OH	WA
VT	VA	OK	WY
WV		SD	
		WI	

Appendix III: Partial deregulation^{lxxxviii}

Structure of the Traditional Utility



Structure of the Deregulated Electric Supply System



Appendix IV: Missing results of FERC survey

This analysis used the number of customers reported by section 6 of the FERC 2010 survey (data for 2009) and compared them to the EIA 2009 Electric Power Annual report. The negative values could be caused by utilities with customers in multiple states calculating their total number of customers differently for each survey.

When looking at the states with over 75% of their customers missing from the FERC data set, it was clear that IOUs which did not report caused most of the missing customers. For example, of the 1.85 million unobserved customers in Oregon, .82 million are customers of Portland General Electric and .55 are customers of Pacific Power.

By looking at the websites of the unrepresented utilities, I was able to find which missing observations had demand response and which did not for the states with the most missing customers. The majority of missing utilities in Montana, Maine, and Mississippi did not offer their customers DR. In Wyoming and Kansas, 3rd party demand response companies offered customers DR but did not report to FERC. Unexpectedly, both Oregon and Georgia had IOUs with multiple demand response programs which did not report to FERC. Portland General Electric (.88 million customers) and Pacific Power (.55 million customers) each offer 12 different demand response programs. Georgia Power (2.3 million customers) have 16 programs for either demand response or energy efficiency.

This paper does not use % customers as a metric for the state level, so the anomalies above will not significantly affect the “implementation choice” analysis. If these programs were outliers in terms of % customers enrolled, they might impact the results of the “enrollment choice” regressions through the regional control variables. It is unlikely, that these programs significantly impacted the results of this paper, but they do imply that FERC could work to get a higher rate of response from utilities with particularly large customer bases.

State	% Cust. Missing	Cust. Represented by FERC	Cust. Represented by EIA	State	% Cust. Missing	Cust. Represented by FERC	Cust. Represented by EIA
AK	100%	415	318,000	UT	23%	817,216	1,059,000
OR	98%	31,742	1,882,000	IA	22%	1,210,619	1,547,000
MT	89%	63,320	570,000	NC	21%	3,811,074	4,838,000
ME	85%	117,559	788,000	IN	20%	2,462,136	3,093,000
GA	85%	716,093	4,623,000	OH	20%	4,395,957	5,515,000
WY	84%	50,855	324,000	VT	18%	293,884	357,000
MS	77%	331,668	1,473,000	CO	18%	2,039,258	2,476,000
KS	75%	357,137	1,451,000	AR	17%	1,259,169	1,524,000
VA	70%	1,092,867	3,602,000	MN	17%	2,138,102	2,574,000
TX	54%	5,032,915	11,056,000	DE	14%	382,991	444,000
MI	51%	2,346,282	4,787,000	AZ	13%	2,482,408	2,851,000
WA	51%	1,575,160	3,188,000	NH	11%	613,277	687,000
SD	46%	235,903	436,000	WI	10%	2,625,707	2,931,000
NY	43%	4,535,490	7,960,000	MA	9%	2,783,415	3,054,000
TN	42%	1,811,410	3,136,000	IL	8%	5,195,466	5,657,000
ND	37%	240,859	382,000	FL	7%	8,963,984	9,639,000
NE	37%	628,124	995,000	PA	5%	5,637,565	5,942,000
AL	35%	1,609,680	2,491,000	NV	5%	1,156,841	1,212,000
NM	34%	647,961	987,000	CA	4%	14,228,048	14,790,000
KY	34%	1,476,122	2,223,000	NJ	3%	3,808,720	3,920,000
LA	32%	1,512,127	2,235,000	WV	2%	997,769	1,015,000
OK	28%	1,391,638	1,928,000	MD	1%	2,412,491	2,440,000
SC	26%	1,797,652	2,432,000	CT	-1%	1,614,084	1,600,000
MO	25%	2,311,639	3,065,000	RI	-2%	499,980	491,000
HI	24%	362,112	474,000	DC	-23%	306,244	248,000
ID	23%	604,290	787,000				

Appendix VI: Implementation Choice Regressions

Percent of utilities with a DR program					
	(1)	(2)	(3)	(4)	(5)#
deregulated	-0.0588*		-0.0559*	-0.0761**	-0.0655
	(0.0326)		(0.0328)	(0.0355)	(0.0436)
dereg cancelled	0.0638		0.0680	0.0657	0.0687
	(0.0439)		(0.0443)	(0.0446)	(0.0438)
decouple or revadj		0.0295	0.0296	0.0287	0.0189
		(0.0362)	(0.0347)	(0.0346)	(0.0328)
# utilities in state				-0.000106	-0.000809**
				(0.000307)	(0.000389)
residential cent/kWh				0.00518	0.0650***
				(0.00379)	(0.0239)
commercial cent/kWh					-0.0442**
					(0.0213)
industrial cent/kWh					-0.0206
					(0.0147)
Constant	0.164***	0.148***	0.156***	0.110*	0.131**
	(0.0196)	(0.0176)	(0.0221)	(0.0555)	(0.0638)
Observations	51	51	51	51	51
R-squared	0.132	0.013	0.145	0.189	0.374
Standard errors in parentheses					
*** p<0.01, ** p<0.05, * p<0.1					
# has controls for geographic regions					

Percent of IOUs with a DR program				
	(1)	(2)	(3)	(4)#
deregulated	-0.205***		-0.199***	-0.134
	(0.0717)		(0.0726)	(0.106)
dereg cancelled	0.0317		0.0400	0.0895
	(0.0964)		(0.0977)	(0.0996)
decouple or revadj		0.0693	0.0540	0.0587
		(0.0811)	(0.0765)	(0.0753)
# IOU				-0.0189**
				(0.00881)
Constant	0.563***	0.485***	0.547***	0.559***
	(0.0438)	(0.0397)	(0.0495)	(0.131)
Observations	50	50	50	50
R-squared	0.169	0.015	0.178	0.345
Standard errors in parentheses				
*** p<0.01, ** p<0.05, * p<0.1				
# has controls for geographic regions and price by customer type i.e. residential				

Percent of public utilities with a DR program					
	(1)	(2)	(3)	(4)	(5)#
deregulated	-0.0280		-0.0224	-0.0392	-0.0410
	(0.0319)		(0.0313)	(0.0407)	(0.0449)
dereg cancelled	0.0303		0.0393	0.0470	0.0266
	(0.0421)		(0.0414)	(0.0417)	(0.0447)
decouple or revadj		0.0569*	0.0583*	0.0567*	0.0478
		(0.0322)	(0.0325)	(0.0323)	(0.0329)
# public				0.000662	1.43e-05
				(0.000398)	(0.000532)
residential cent/kWh				0.00652	0.0515*
				(0.00566)	(0.0262)
commercial cent/kWh					-0.0271
					(0.0229)
industrial cent/kWh					-0.0188
					(0.0148)
Constant	0.0700***	0.0518***	0.0527**	-0.0418	-0.0644
	(0.0191)	(0.0159)	(0.0210)	(0.0630)	(0.0769)
Observations	49	49	49	49	49
R-squared	0.037	0.062	0.101	0.170	0.259
Standard errors in parentheses					
*** p<0.01, ** p<0.05, * p<0.1					
# has controls for geographic regions					

Percent of coops with a DR program				
	(1)	(2)	(3)	(4)#
deregulated	-0.205***		-0.199***	-0.134
	(0.0717)		(0.0726)	(0.106)
dereg cancelled	0.0317		0.0400	0.0895
	(0.0964)		(0.0977)	(0.0996)
decouple or revadj		0.0693	0.0540	0.0587
		(0.0811)	(0.0765)	(0.0753)
# coops				-0.0189**
				(0.00881)
Constant	0.563***	0.485***	0.547***	0.559***
	(0.0438)	(0.0397)	(0.0495)	(0.131)
Observations	50	50	50	50
R-squared	0.169	0.015	0.178	0.345
Standard errors in parentheses				
*** p<0.01, ** p<0.05, * p<0.1				
# has controls for geographic regions and price by customer type i.e. residential				

Appendix VII: Program Choice Regressions

	Price Programs per Utility					
	(1)	(2)	(3)#	(4)&	(5)&	(6)#&
dereg	-1.223***		-1.151***	-0.589***		-0.534***
	(0.345)		(0.386)	(0.124)		(0.153)
deregcancel	0.353		0.223	0.148		0.0562
	(0.475)		(0.476)	(0.199)		(0.211)
decoup_revad		1.979***	1.689***		1.14***	0.839***
		(0.420)	(0.417)		(0.282)	(0.263)
coop	-2.026***	-1.306***	-1.244***	-1.501***	-1.24***	-1.023***
	(0.279)	(0.211)	(0.307)	(0.146)	(0.121)	(0.161)
deregcoop	1.214***		0.869*	0.844*		0.480
	(0.459)		(0.460)	(0.444)		(0.376)
cancelderegcoop	-0.800		-0.735	-0.762***		-0.756***
	(0.573)		(0.571)	(0.180)		(0.184)
decoup_revadcoop		-2.115***	-1.644**		-0.736***	-0.638**
		(0.769)	(0.754)		(0.256)	(0.278)
publicutility	-1.062***	-0.446*	-0.481	-0.521***	-0.291***	-0.299**
	(0.289)	(0.227)	(0.318)	(0.109)	(0.107)	(0.134)
deregpublic	0.0796		-0.262	-0.452*		-0.585***
	(0.533)		(0.531)	(0.239)		(0.208)
cancelderegpublic	-0.537		-0.340	-0.246		-0.121
	(0.655)		(0.783)	(0.245)		(0.349)
decoup_revadpublic		-2.100***	-2.058**		-0.669***	-0.590**
		(0.720)	(0.931)		(0.181)	(0.256)
reseprice			0.491***			0.390***
			(0.147)			(0.089)
comeprice			-0.264*			-0.222**
			(0.141)			(0.0887)
indeprice			-0.199**			-0.176***
			(0.0928)			(0.0550)
cust_tot			0.000414**			0.000140**
			(0.000179)			(0.00006)
Constant	2.857***	2.067***	0.852			
	(0.239)	(0.175)	(0.826)			
Observations	528	528	509	528	528	509
R-squared	0.162	0.155	0.234			
Standard errors in parentheses						
*** p<0.01, ** p<0.05, * p<0.1						
# has controls for regions, % of customers by sector (i.e. residential), & is MFX from a Poisson model						

Price Program Binary						
	(1)	(2)	(3)#	(4)&	(5)&	(6)&#
dereg	-0.154*	0.0150	-0.138	-0.171*	0.0155	-0.164
	(0.0925)	(0.0527)	(0.105)	(0.099)	(0.0530)	(0.118)
deregcancel	0.0921	-0.0599	0.0133	0.126	-0.0596	0.0379
	(0.128)	(0.0639)	(0.130)	(0.144)	(0.0651)	(0.153)
decoup_revad		0.223***	0.0664		0.219***	0.0764
		(0.0826)	(0.114)		(0.0715)	(0.127)
coop	-0.282***		-0.218***	-0.293***		-0.225**
	(0.0750)		(0.0838)	(0.077)		(0.0926)
Dereg*coop	0.242*		0.202	0.234**		0.200*
	(0.123)		(0.125)	(0.102)		(0.111)
Canceldereg*coop	-0.329**		-0.304*	-0.365***		-0.358**
	(0.154)		(0.156)	(0.141)		(0.154)
decoup_revad*coop			-0.213			-0.219
			(0.206)			(0.218)
publicutility	-0.168**		-0.134	-0.184**		-0.156
	(0.0775)		(0.0867)	(0.084)		(0.0987)
Dereg*public	0.137		-0.00773	0.146		0.000325
	(0.143)		(0.145)	(0.134)		(0.157)
Canceldereg*public	0.159		0.000970	0.161		0.0375
	(0.176)		(0.213)	(0.184)		(0.253)
decoup_revad*public			-0.0684			-0.0510
			(0.254)			(0.335)
rescustshare			-0.451**			-0.647**
			(0.220)			(0.297)
comcustshare			0			0
			(0)			(0)
othrcustshare			-0.887**			-1.10**
			(0.360)			(0.432)
northeast			-0.0132			-0.0175
			(0.0920)			(0.101)
west			0.224***			0.221***
			(0.0794)			(0.0708)
south			0.129**			0.134**
			(0.0551)			(0.0576)
Constant	0.750***	0.545***	0.762***			
	(0.0642)	(0.0275)	(0.225)			
Observations	528	528	509	528	528	509
R-squared	0.081	0.015	0.143			
Standard errors in parentheses						
*** p<0.01, ** p<0.05, * p<0.1						
# has controls for price of electricity by sector (i.e. residential) and total # customers						
& probit model MFX						

Number of RTP Programs per Utility				
	(1)	(2)	(3)	(4)#
dereg	-0.169***		-0.150***	-0.127**
	(0.0489)		(0.0489)	(0.0542)
deregcancel	-0.0404		-0.0397	-0.000754
	(0.0675)		(0.0670)	(0.0670)
decoup_revad		0.219***	0.195***	0.201***
		(0.0594)	(0.0596)	(0.0586)
coop	-0.297***	-0.182***	-0.255***	-0.170***
	(0.0397)	(0.0298)	(0.0415)	(0.0432)
Dereg*coop	0.185***		0.165**	0.132**
	(0.0652)		(0.0650)	(0.0646)
Canceldereg*coop	0.0339		0.0328	-0.00309
	(0.0814)		(0.0809)	(0.0803)
decoup_revad*coop		-0.227**	-0.206*	-0.216**
		(0.109)	(0.109)	(0.106)
publicutility	-0.287***	-0.177***	-0.245***	-0.177***
	(0.0410)	(0.0321)	(0.0427)	(0.0447)
Dereg*public	0.153**		0.133*	0.112
	(0.0757)		(0.0754)	(0.0747)
Canceldereg*public	0.0240		0.0233	0.0108
	(0.0931)		(0.114)	(0.110)
decoup_revad*public		-0.232**	-0.195	-0.163
		(0.102)	(0.134)	(0.131)
cust_tot				8.77e-05***
				(2.52e-05)
Constant	0.304***	0.190***	0.262***	0.354***
	(0.0340)	(0.0247)	(0.0361)	(0.116)
Observations	528	528	528	509
R-squared	0.139	0.141	0.157	0.192
Standard errors in parentheses				
*** p<0.01, ** p<0.05, * p<0.1				
# has controls for regions, % of customers by sector (i.e. residential), price per kWh by sector				

Appendix VIII: Enrollment Choice Regressions

% Utility total customers in Demand Response			
	(1)	(2)	(4)#
dereg	-0.0188 (0.0530)	-0.0173 (0.0533)	0.0749 (0.0506)
deregcancel	-0.0469 (0.0716)	-0.0467 (0.0716)	0.0140 (0.0623)
decoup_revad		0.0153 (0.0637)	0.0140 (0.0545)
coop	0.144*** (0.0426)	0.150*** (0.0450)	0.0969** (0.0399)
Dereg*coop	-0.0692 (0.0708)	-0.0702 (0.0710)	-0.0879 (0.0601)
Canceldereg*coop	0.0169 (0.0867)	0.0141 (0.0867)	0.0210 (0.0746)
decoup_revad*coop		-0.0824 (0.116)	0.0218 (0.0984)
publicutility	0.0372 (0.0442)	0.0406 (0.0463)	0.0449 (0.0417)
Dereg*public	0.0412 (0.0819)	0.0397 (0.0820)	0.0211 (0.0697)
Canceldereg*public	0.0576 (0.0988)	0.190 (0.121)	0.187* (0.102)
decoup_revad*public		-0.254* (0.142)	-0.197 (0.122)
comcustshare			0.0256 (0.106)
sumdlc			0.0942*** (0.00714)
Constant	0.0885** (0.0365)	0.0851** (0.0392)	0.0731 (0.0637)
Observations	509	509	509
R-squared	0.051	0.059	0.355
Standard errors in parentheses			
*** p<0.01, ** p<0.05, * p<0.1			
# has controls for region, price of electricity by sector (i.e. residential) , and total number of customers			

Appendix IX: TOU Correlation with Deregulation

Deregulation		
	(1)	(2)
% utilities with TOU	-0.0239 (0.232)	
% IOUs with TOU		-0.184 (0.185)
Constant	0.326** (0.140)	0.452*** (0.137)
Observations	51	48
R-squared	0.000	0.021
Standard errors in parentheses		
*** p<0.01, ** p<0.05, * p<0.1		

```
. correlate dereg perstutiltou
(obs=51)
```

	dereg perstu~u	
dereg	1.0000	
perstutiltou	-0.0147	1.0000

```
. correlate dereg perstioutou
(obs=48)
```

	dereg persti~u	
dereg	1.0000	
perstioutou	-0.1457	1.0000

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