UTILITY RATE DESIGN INITIATIVE: ANALYSIS NARRATIVE MAY 12, 2016

As part of the Utility Rate Design Initiative, the Alliance to Save Energy executed two technical analyses and a review of literature. The first analysis investigated OpenEI's U.S. Utility Rate Database, an open-source utility tariff database, while the second analyzed the Energy Information Administration's Form 861 data. Additionally, the Alliance reviewed approximately 35 whitepapers and technical documents that helped inform and shape its position on rate design.

This narrative accompanies and enhances the presentation materials from the May 12, 2016 kickoff meeting. Both technical analyses are presented with additional background on process and results, and a summary of selected whitepapers expands on the presentation's high level overview. Two appendices are included, the first containing the ACEEE Scorecard-based state rankings that were used in the two analyses, and the second containing a list of sources that were reviewed as part of this phase of the initiative.

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ACRONYMS

AMI: Advanced Metering Infrastructure

DER: Distributed Energy Resources

DG: Distributed Generation

CPP: Critical Peak Pricing

DP: Dynamic Pricing

DR: Demand Response

DSM: Demand Side Management

EE: Energy Efficiency

EERS: Energy Efficiency Resource Standard

EM&V: Evaluation, Measurement, and Verification

LRAM: Lost Revenue Adjustment Mechanism

PIM: Performance Incentive Mechanism

RDI: Rate Design Initiative

RPS: Renewable Portfolio Standard

TOU: Time of Use

TVR: Time-Varying Rates (includes TOU and DPP)

VI: Vertically Integrated

OPENEI U.S. UTILITY RATE DATABASE ANALYSIS

The first Utility Rate Design Initiative (RDI) technical analysis investigated the OpenEI U.S. Utility Rate Database. This database, hosted by non-profit Open Energy Information, contains detailed information about utility rate tariffs. Users can search by zip code, utility name, sector (e.g. residential, commercial, industrial, and lighting) and effective date. The database contains almost 40,000 tariffs as of May 2016 (including 30,500 active tariffs from over 2,800 utilities), and additional tariffs are added or updated frequently.

For its analysis, the Alliance made two decisions to limit the scope of the dataset. First, it excluded lighting tariffs from detailed analysis. While lighting tariffs are an interesting aspect to rate design, they are sufficiently distinct in their characteristics from traditional residential, commercial, and industrial tariffs to merit their exclusion as part of this effort. Second, it focused primarily on Municipal, Cooperative, and IOU tariffs. This excluded tariffs from political subdivisions (i.e. irrigation districts), state, and federal tariffs. After applying these two filters, nearly 75% or 23,000 tariffs remained of the original dataset, shown in green below.

	Municipal	Cooperative	IOU	Political Subdivision	State	Federal	Retail Power Marketer	Grand Total
Count of Utilities	1,786	757	169	95	7	4	2	2,820
Tariffs by Sector								
Commercial	6,246	3,931	2,002	739	83	77		13,078
Industrial	2,447	1,442	788	267	17	10		4,971
Residential	3,254	1,836	881	224	25	2	3	6,225
Lighting	3,101	2,434	310	405	14	5		6,269
Grand Total	**15,048**	**9,643**	**3,981**	**1,635**	**139**	**94**	**3**	**30,543**

One of the limitations of the tariff database is that it does not include the level of participation of a particular tariff. While this precludes the ability to produce weighted averages of certain rate characteristics, the database is still amenable to the analysis of prevalence of a given characteristic.

Five major tariff charges were analyzed. These include:

Fixed (i.e. customer) charges

Charges that appear on every bill every billing cycle, regardless of energy use or demand levels.

Seasonal/monthly demand charges

Charges that are based on the highest demand of a customer over a billing period, typically measured in $/kW (but sometimes in $/kVA or $/HP). Seasonal demand charges may include a different demand rate for summer and winter months, while monthly tariffs might vary by month. Additionally, demand tariffs may have different tiers (i.e. one up to 100 kW and another for over 100 kW) with correspondingly different rate levels.

Time of use demand charges

Charges that are based on the highest demand of a customer over a shorter time frame, analogous to the more common time of use energy rates. In these rates, customers might face one rate during weekday peak hours and another during weekend or off-peak hours. There may also be a seasonal component to the rate levels.

Seasonal/monthly energy charges

Charges that are based on a $/kWh rate. As with seasonal or monthly demand charges, these rates may vary season-to-season or month-to-month, and may have different tiers with different prices.

Time of use (TOU) energy charges

Charges that are based on a $/kWh rate that vary based on what time of day or week the energy is consumed. A typical rate structure might include on-peak, intermediate, and off-peak period rates. TOU tariffs can also include a seasonal aspect or a tiered structure.

Tariffs were analyzed through three main groupings.

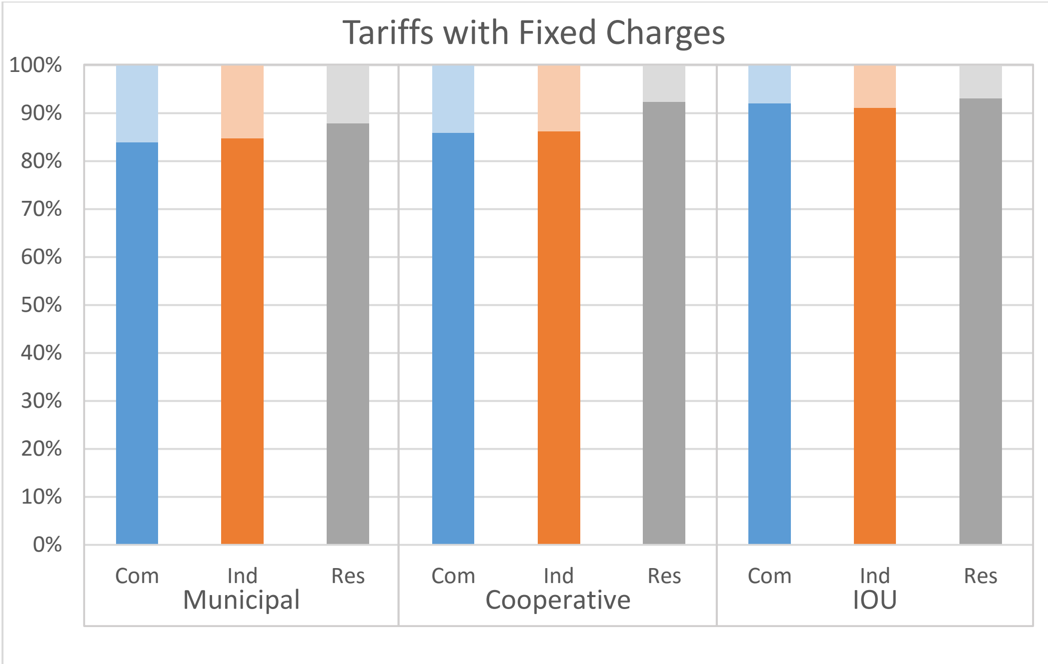
Grouping	Details
Utility type	Tariffs grouped by municipal, cooperative, and IOU utilities. Other ownership types (political subdivision, federal, state, and retail power marker) were not analyzed in detail.
Sector	Tariffs grouped by Commercial, Industrial, and Residential. Lighting tariffs were not analyzed in detail.
ACEEE Quintile ranking	ACEEE Quintile rankings were calculated from the cardinal rank of the average rank of each state's 2011-2015 scorecard. Rankings are included in Appendix A.

By analyzing trends across sectors and across utility types, and comparing rate characteristics to ACEEE rankings, the Alliance was able to glean some insights from the dataset that might help inform RDI ratemaking principles. Each characteristic was analyzed to determine how often it was found in the tariffs of each utility type and sector. In the charts that follow, the darker shading indicates the percentage of the tariffs with that characteristic. For fixed charges and demand charges, histograms showing the relative scale of the charges were calculated for each combination.[1] Additional analyses on inclining and declining block structures and on TOU rates are found in their respective sections.

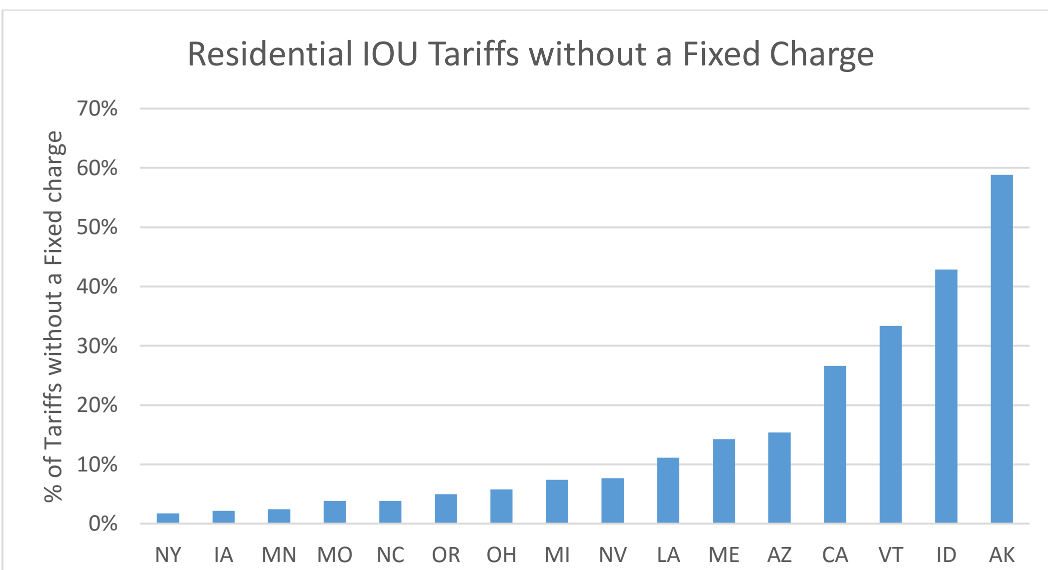
[1] Histograms for energy charges were not calculated as they tend to be driven more by an individual utility's fuel costs (for vertically integrated utilities) and/or the residual revenue requirement after fixed and demand charges are taken into account.

Fixed Charges

Fixed charges are a staple of tariffs found in the OpenEI database. For each sector/utility ownership combination, almost 85% of tariffs included some sort of fixed charge.[2] For IOUs, the figure exceeds 90% across all sectors.



For IOU residential tariffs, 32 states had a fixed charge in 100% of their database tariffs. For the other 18 states, most had fewer than 10% of tariffs without a fixed charge. Notable exceptions include California, where 27% of residential tariffs lacked a fixed charge, and Alaska, where nearly 60% did not have a fixed charge.



When one looks at the distribution of fixed charges, some observations can be made based on the sector and ownership structure of the utility.

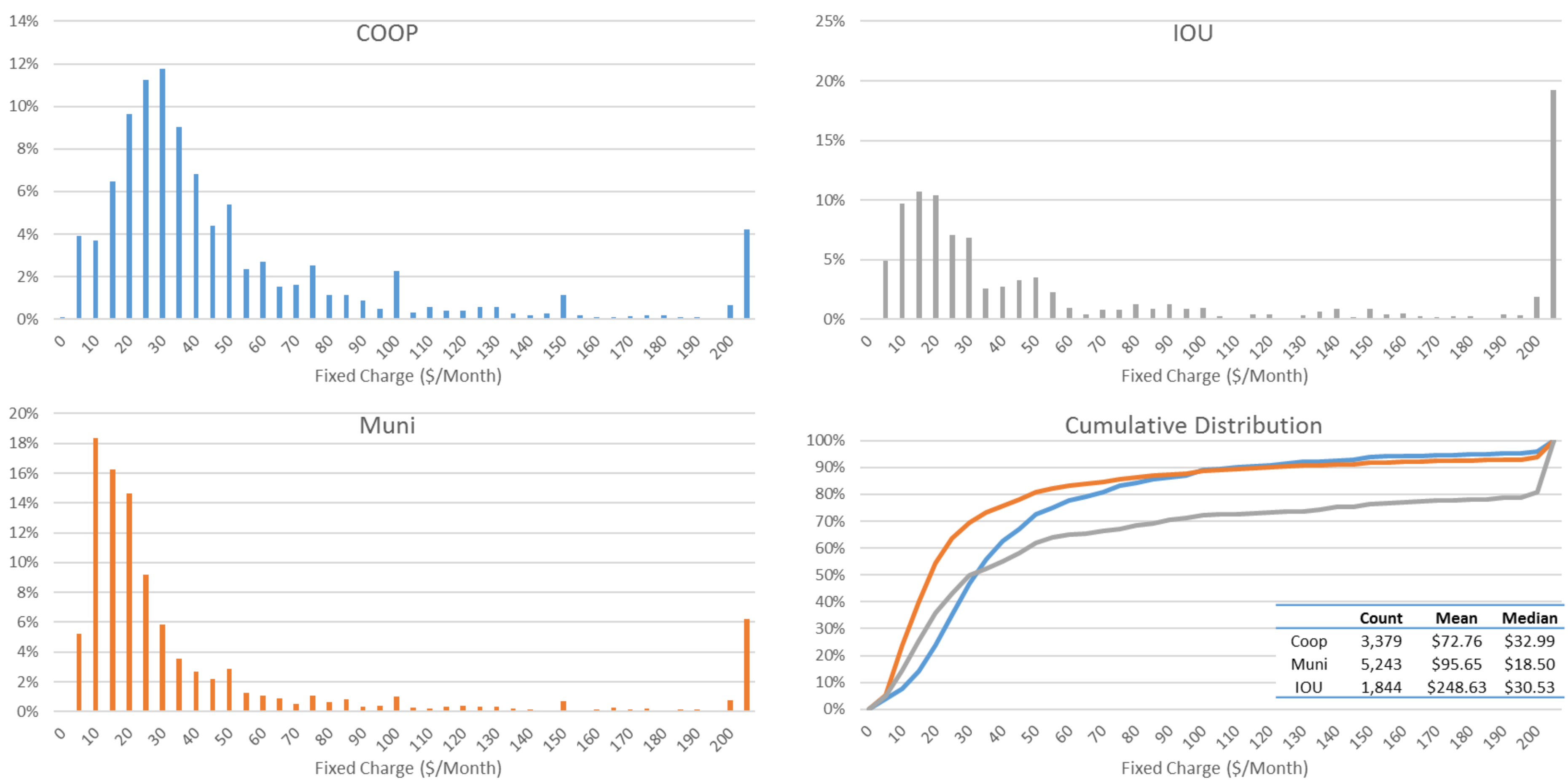
[2] In each of the stacked vertical bar charts, the percentage of tariffs with the characteristics is shaded darker, while the balance without the characteristic is shaded lighter.

Within the commercial sector, there was a reasonable amount of variation in the fixed charge distribution. Generally, municipal utilities had the lowest fixed charges, with peaks occurring at $10/month and 70% having a charge of $30/month or less. On the other hand, the most common fixed charge for IOUs (nearly 20% of tariffs) exceeded $200/month. Cooperatives were somewhat in the middle of the two distributions, with more tariffs clustered around $30/month, but with a reasonable proportion over $200/month. These differences also emerge when looking at the mean and median fixed charge. IOUs have by far the highest average, driven by the large quantity of tariffs with high fixed charges. But the median commercial tariff for IOUs is actually slightly lower than the median commercial tariff for coops.

Industrial tariffs tell a different story. Here, the distribution of the coop and municipal utilities is nearly identical, but the IOU is starkly different. As with the commercial sector, IOU fixed charges in the industrial sector are skewed toward the high end of the spectrum. In this distribution, roughly a third of all tariffs exceeded $800/month, while only 12% of coop and muni industrial tariffs were above this level. Again, the mean and median reflect this story with the average industrial IOU tariff fixed charge set 7 and 9 times higher than the muni and coop, respectively.

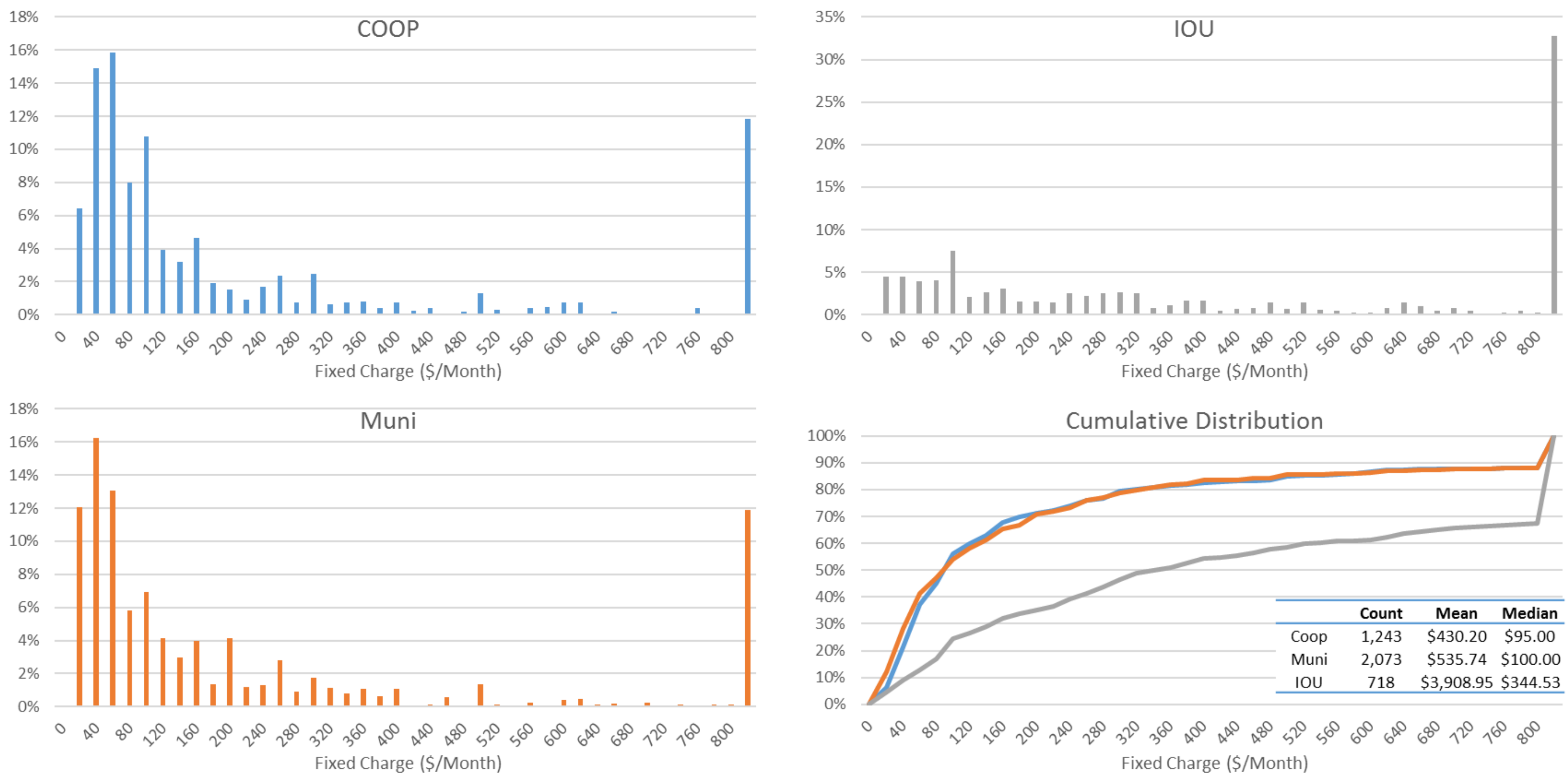
Curiously, the residential tariffs tell a similar story to the industrial but with a change in the actors. In this sector, the muni and IOU customers are virtually indistinguishable, with the coops acting as the outlier. Coop fixed charges are higher and their distribution is broader, with a larger proportion of high outlier fixed charges. One possible reason for this is that many rural coops classify agricultural customers under their residential tariff, skewing their dataset with “commercial-like” tariffs. Nonetheless, the median cooperative residential customer (who is insulated from the upward skew of the mean customer) pays $21.50/month in fixed charges, as compared to $9.00 and $9.57 per month for muni and IOU residential customers, respectively. By the time the IOU distribution hits $21.50 per month, 93% of ratepayers will have lower fixed charges.

Fixed Charge Histogram – Commercial Tariffs



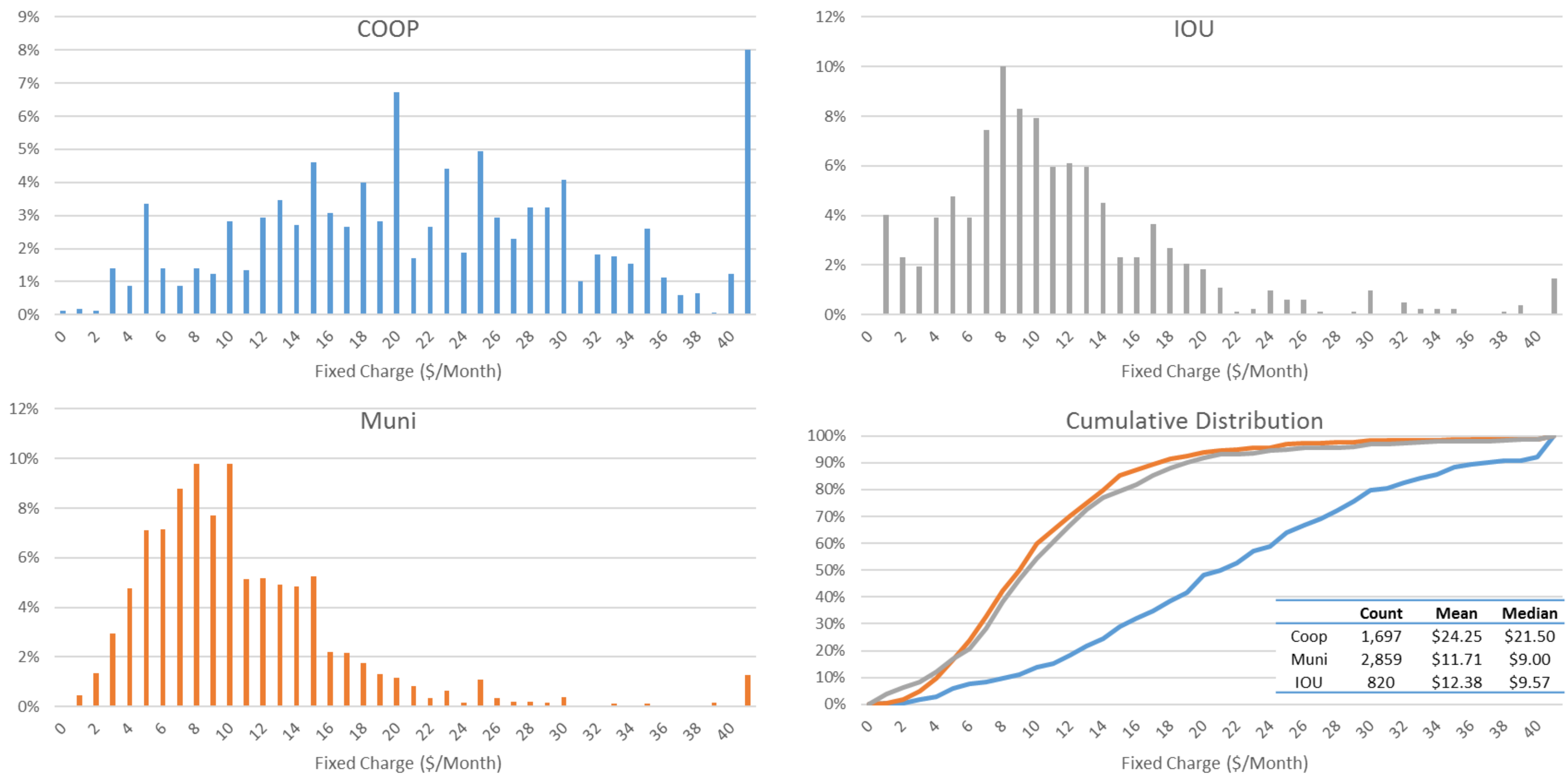
	Count	Mean	Median
Coop	3,379	$72.76	$32.99
Muni	5,243	$95.65	$18.50
IOU	1,844	$248.63	$30.53

Fixed Charge Histogram – Industrial Tariffs



	Count	Mean	Median
Coop	1,243	$430.20	$95.00
Muni	2,073	$535.74	$100.00
IOU	718	$3,908.95	$344.53

Fixed Charge Histogram – Residential Tariffs



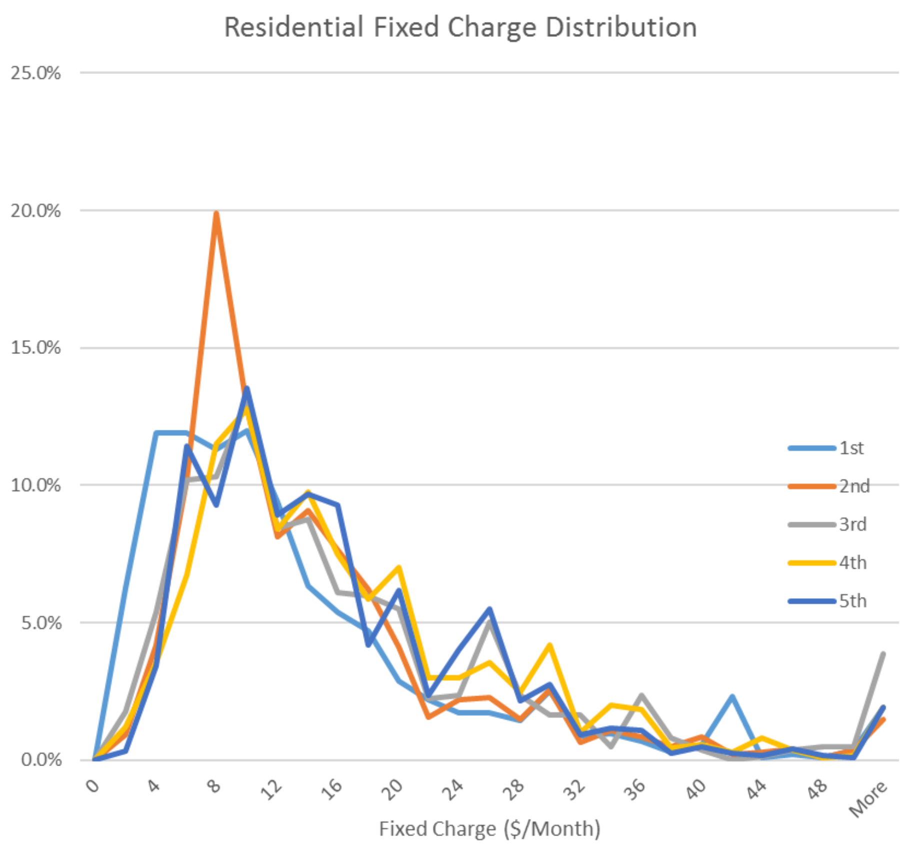
	Count	Mean	Median
Coop	1,697	$24.25	$21.50
Muni	2,859	$11.71	$9.00
IOU	820	$12.38	$9.57

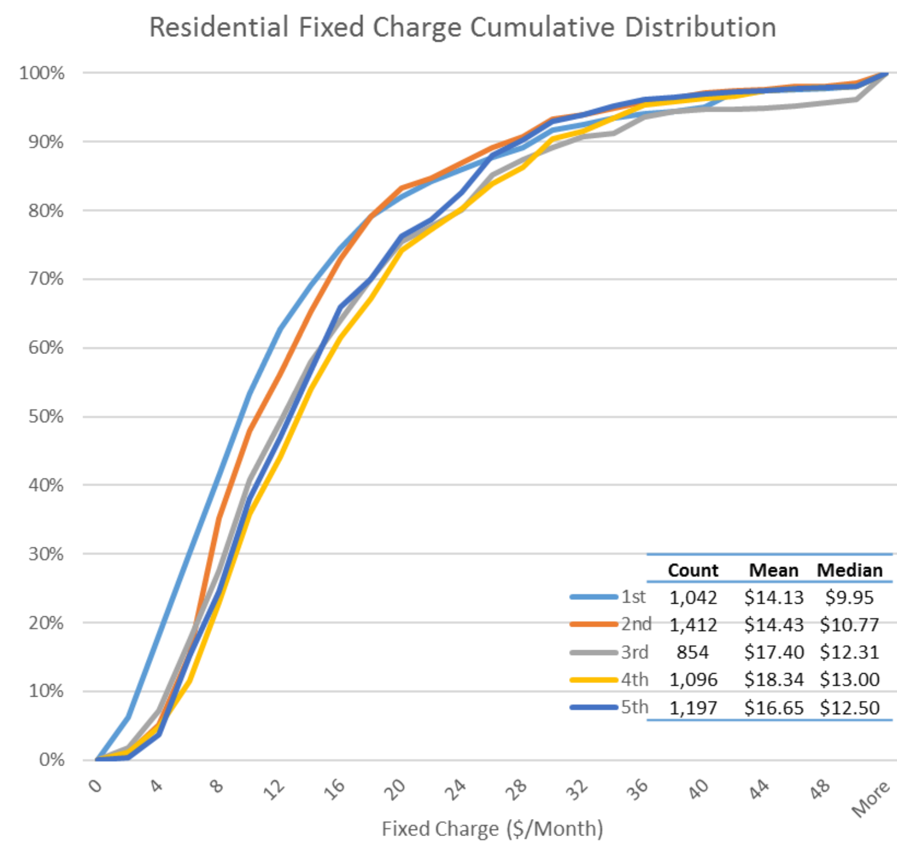
The last set of fixed charge analysis compares the prevalence of fixed charge levels to ACEEE Quintile performance. In these charts, each sector was analyzed by state across utility ownership structures, and a common distribution based on ACEEE Quintile was developed. While this methodology does combine several factors that might influence utility energy efficiency performance, some patterns do emerge from the data.

For residential customers, energy efficiency performance (as measured by the proxy of ACEEE Quintile ranking) is correlated with lower fixed charges. The mean fixed charge for the top two quintiles was $3.20 lower than the bottom three quintiles, a reduction of almost 20%. The lower fixed charges are maintained throughout the cumulative distribution until the tariffs begin to converge around the 90th percentile.

For commercial customers, the relationship is not as strong across the spectrum. In fact, the cumulative distribution for the 2nd and 5th quintiles have the lowest fixed charges, with the 1st, 3rd, and 4th more closely distributed on the high end of the fixed charge spectrum. That said, the data for the lower half of the distribution (i.e. customers with lower than median fixed charges) show 1st and 2nd quintile states with lower fixed charges than the other three quintile states.

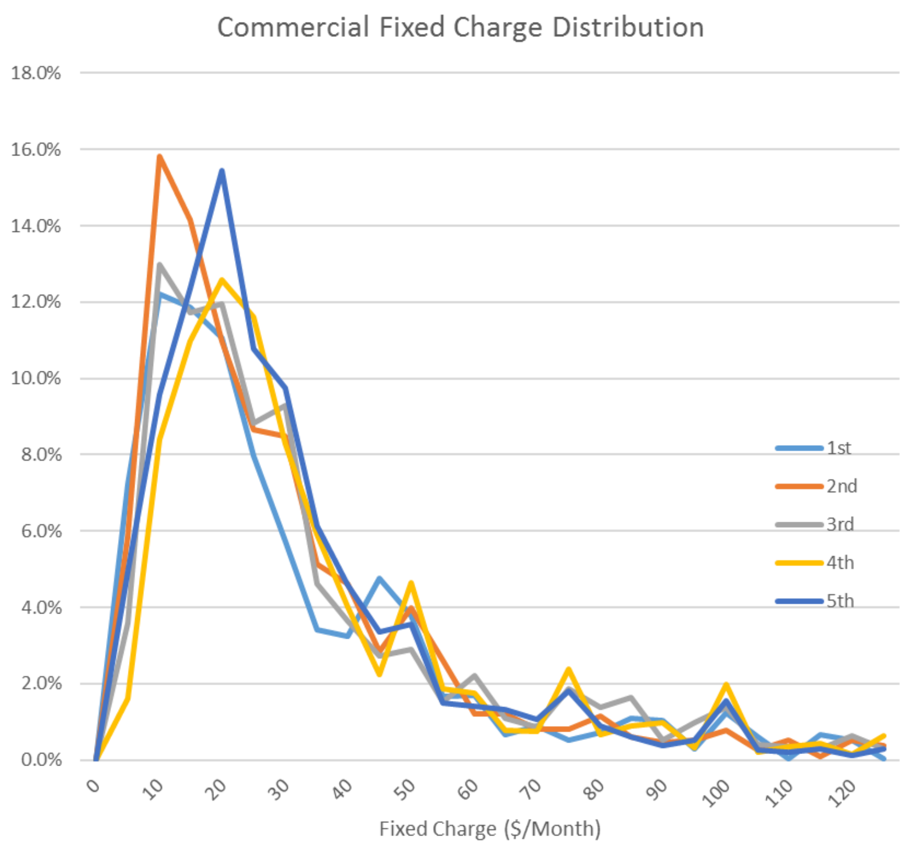
Residential Fixed Charges by ACEEE Quintile

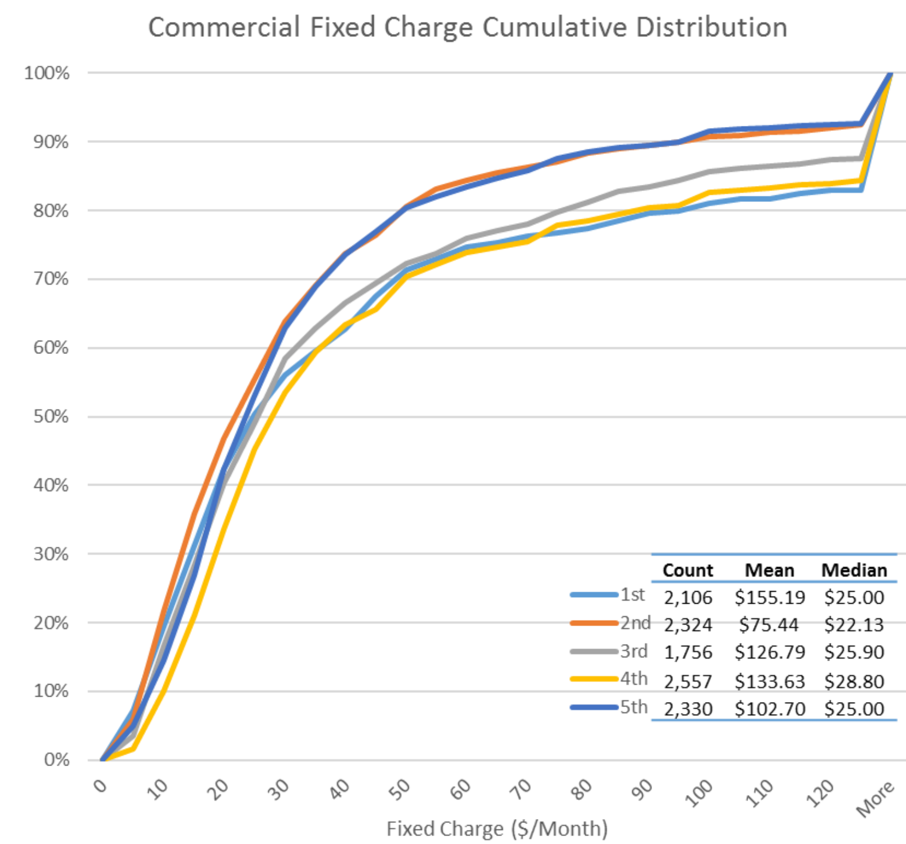




	Count	Mean	Median
1st	1,042	$14.13	$9.95
2nd	1,412	$14.43	$10.77
3rd	854	$17.40	$12.31
4th	1,096	$18.34	$13.00
5th	1,197	$16.65	$12.50

Commercial Fixed Charges by ACEEE Quintile

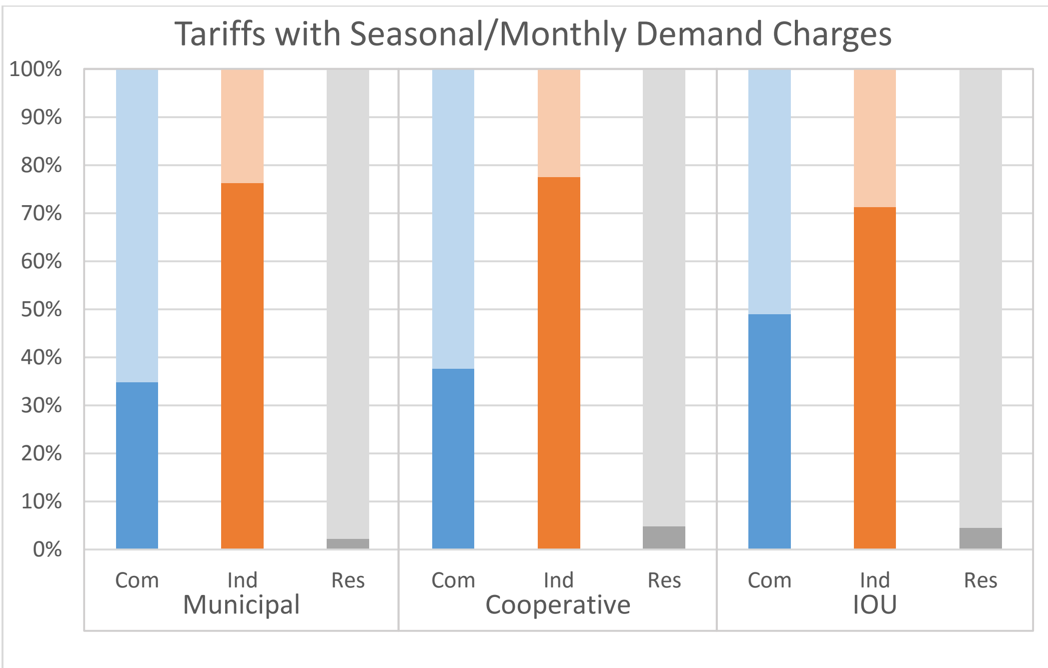




Seasonal/Monthly Demand Charges

Seasonal/monthly demand charges are incurred based on the peak demand of the customer within a billing period. Demand levels are most often calculated on a one-hour, thirty-minute, or fifteen-minute average. Most demand charges were billed based on peak kW, but some were measured in kVA (kilo-volt-amps, a measure of apparent power that varies based on the real power and power factor[3]) or horse power.[4]

Across ownership structure, industrial tariffs were by far the most likely to have seasonal demand charges. More than 70% of each utility structure industrial tariffs included demand charges, while only 35%-50% of commercial tariffs contained demand charges. IOUs were the most likely group to have commercial demand charges, accounting for nearly half of their commercial tariffs. Residential demand charges are currently very limited, and while they registered in the low-single digits of prevalence, in practice they tend to be limited to voluntary, opt-in programs with very low levels of participation.[5]



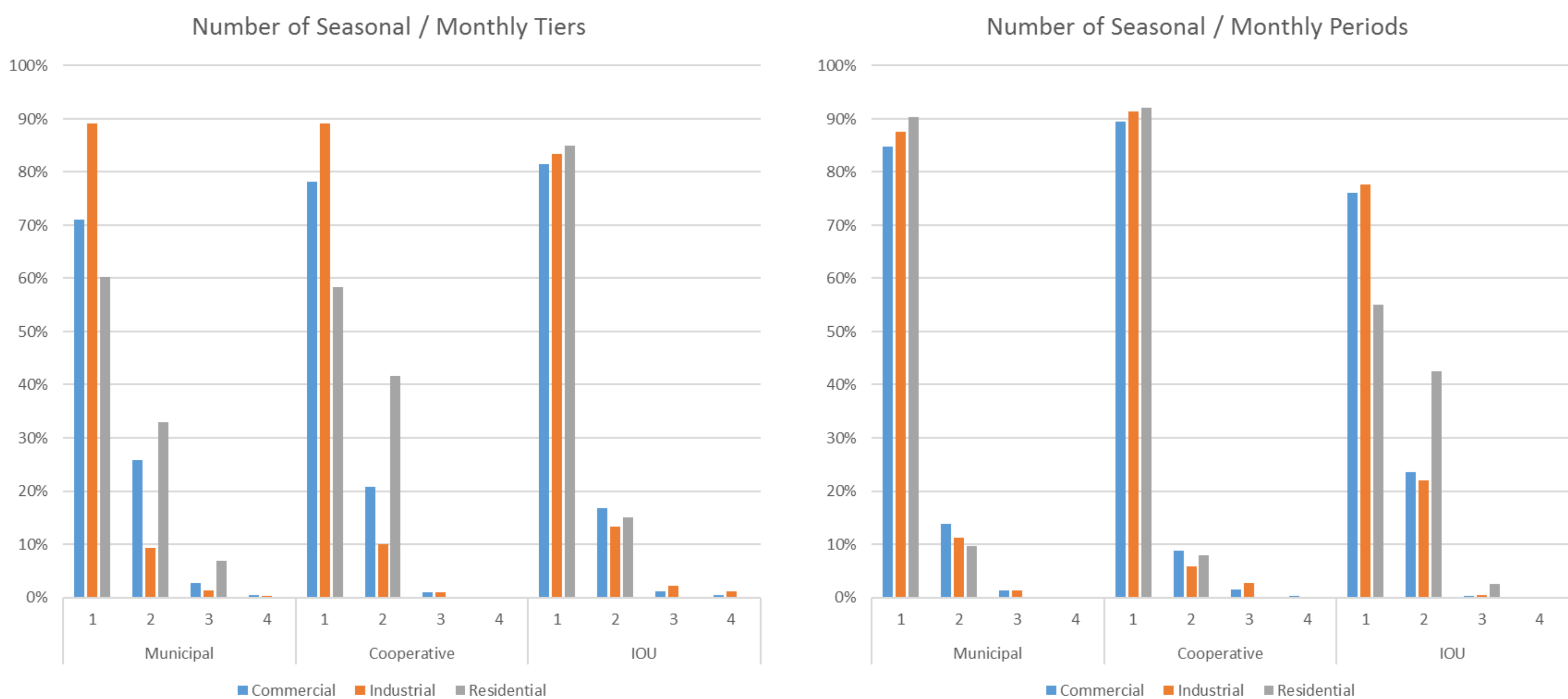
Seasonal/monthly demand charge tariffs contained both "tiers" and "periods." In this context, tiers represent the number of distinct demand levels with different rates, while periods represent how often a rate varies for a given level of demand. For example, a tariff with two demand tiers may have one demand rate for a customer that registers between 0 and 50 kW in a peak period, and a second rate if that customer exceeds 50 kW in a peak period. On the other hand, a tariff with two demand periods might have one rate for weekdays and one for weekend, independent of the level of demand attained. To complicate matters further, some tariffs have both multiple tiers and multiple periods.

[3] Real power, measured in kW, is that which can be used to do electromechanical work. Apparent power is measured in kVA and is the mathematical product of the voltage and the amperage. Power factor is the ratio of real power to apparent power, and is used to measure inefficiencies caused by AC frequency leads or lags caused by inductive or capacitive loads. For example, a 100 kW motor with a 0.9 power factor will consume 100 kW of real power at full load, but must be provided 111 kVA (100/0.9) of apparent power from the distribution grid.

[4] All tariffs delineated in HP were converted to kW.

[5] There are some proposed changes to shift residential customers to demand charges, such as in Illinois and Arizona.

Seasonal / Monthly Demand Charge Details



Tariffs with a single annual demand charge were analyzed in more detail. As seen above, a large percentage of tariffs with demand charges billed a constant price per kW throughout the year (indicated by the “1” entry under each utility type in the right chart above.) Unlike the fixed charge histograms, there was not a substantial variation between the utility types in a given sector.

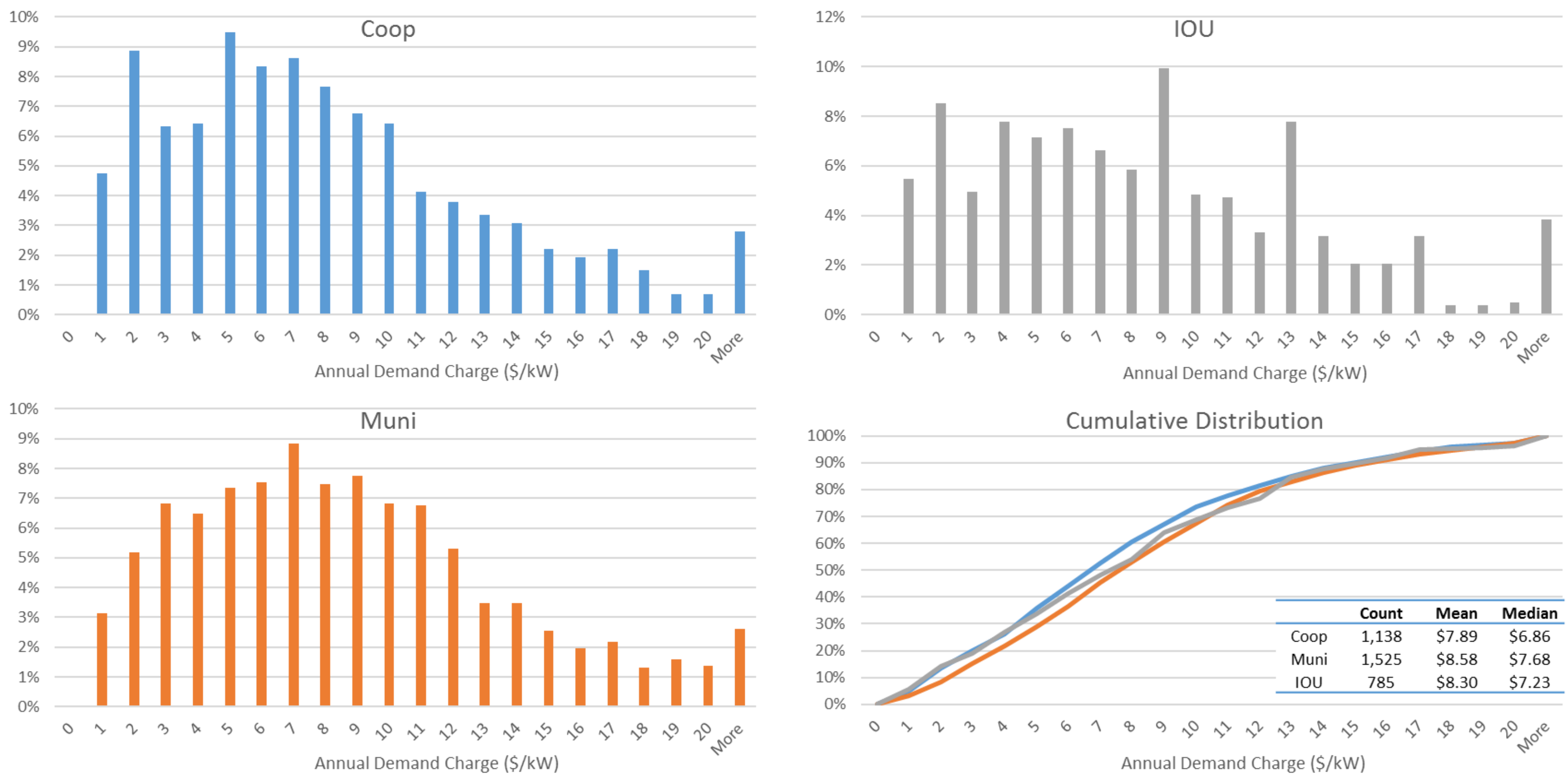
In the commercial sector, the distribution of demand levels was fairly similar. Median rates were slightly lower for coops ($6.86/kW) than for munis ($7.68/kW) and IOUs ($7.23/kW), but the cumulative distribution was not driven by an unusually high level of outliers.

Industrial tariffs had a bit more variation, with IOUs generally skewing towards the low end of the price distribution. Municipal utilities had a large peak in the $2/kW range (with nearly 20% of industrial tariffs in that bucket), but were otherwise fairly evenly distributed. Coops peaked around $7/kW.

Interestingly, the median and mean demand charges were about 25% and 22% higher, respectively, for IOU commercial customers than for IOU industrial customers.

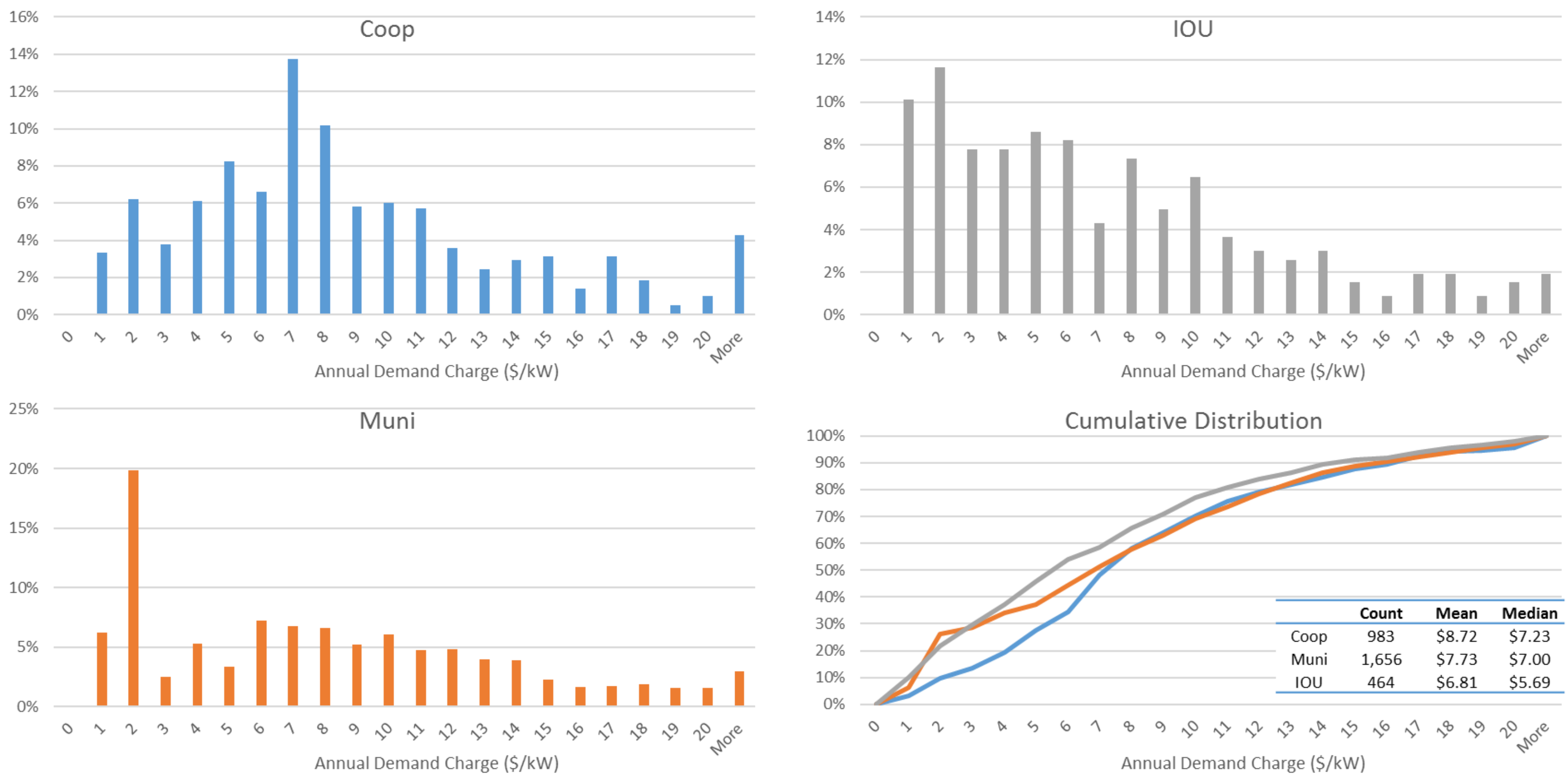
Residential annual demand charges are not very common, with only 128 in the active tariff dataset. But for the small sample, the levels and distribution were relatively consistent across the utility types. Average residential demand rates were in between commercial and industrial levels.

Annual Demand Charge Histogram – Commercial



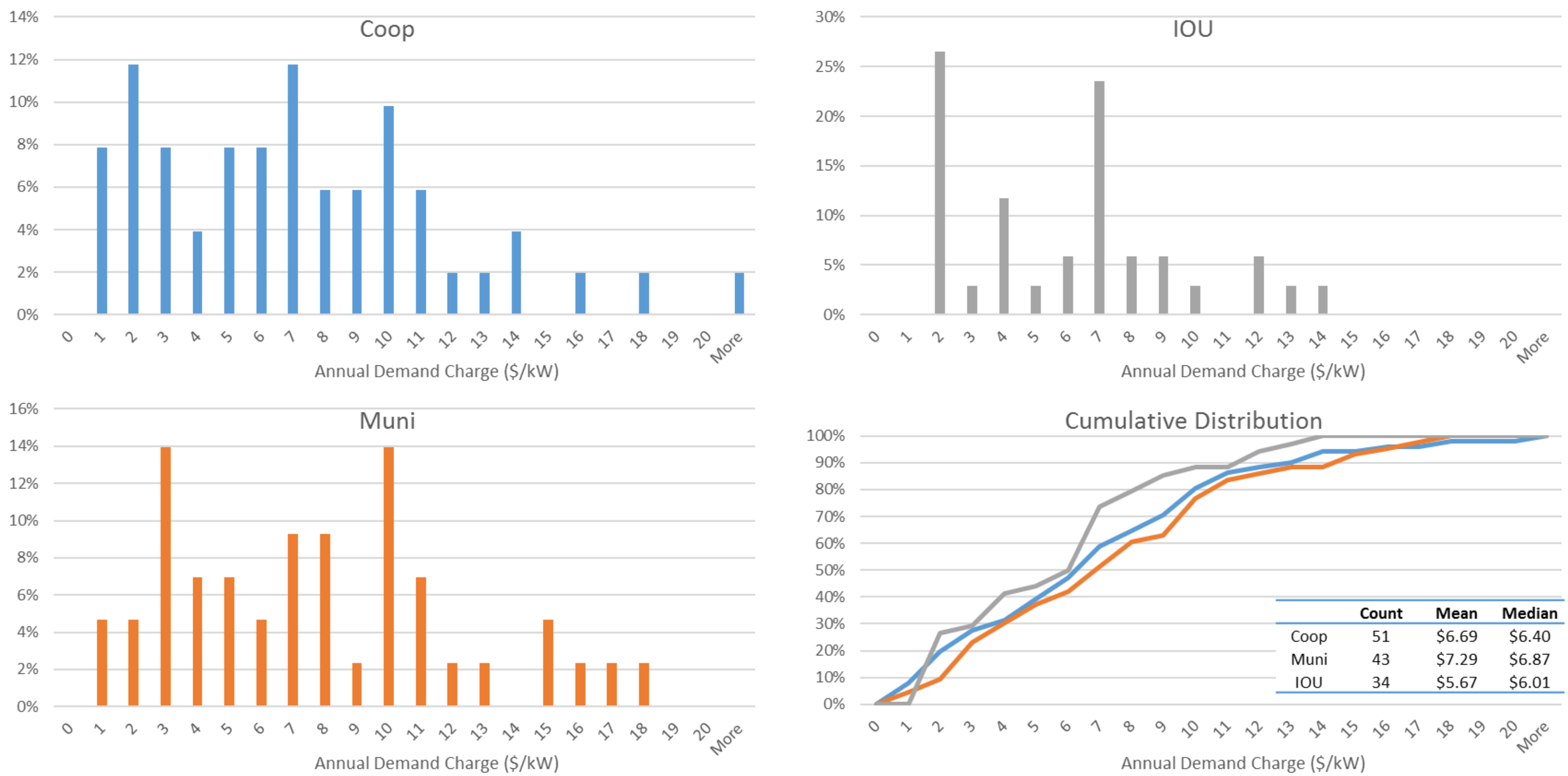
	Count	Mean	Median
Coop	1,138	$7.89	$6.86
Muni	1,525	$8.58	$7.68
IOU	785	$8.30	$7.23

Annual Demand Charge Histogram – Industrial



	Count	Mean	Median
Coop	983	$8.72	$7.23
Muni	1,656	$7.73	$7.00
IOU	464	$6.81	$5.69

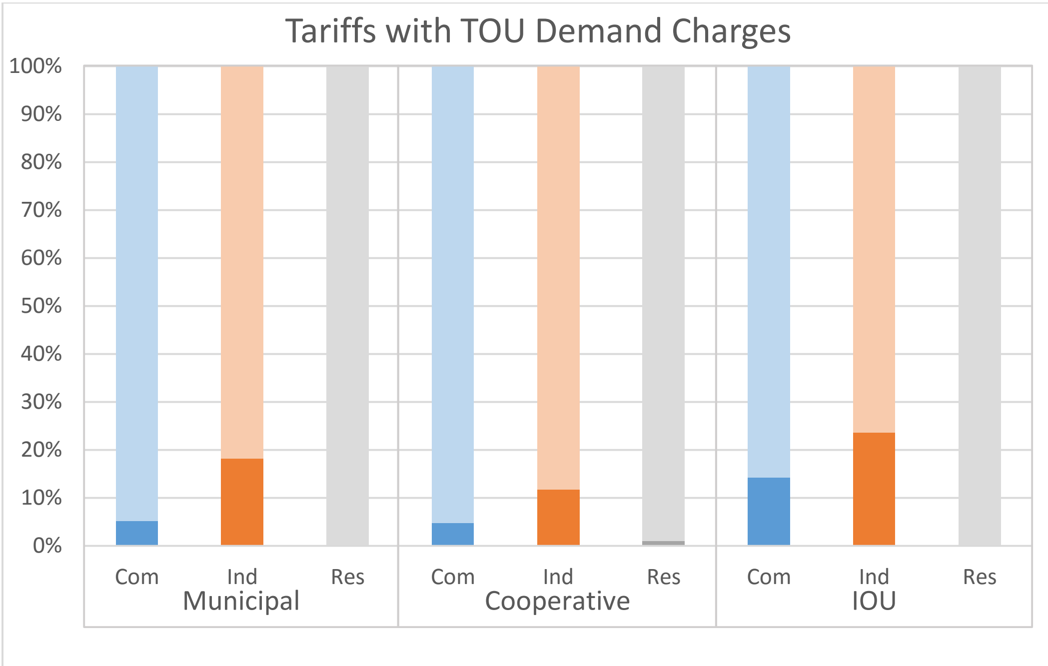
Annual Demand Charge Histogram – Residential



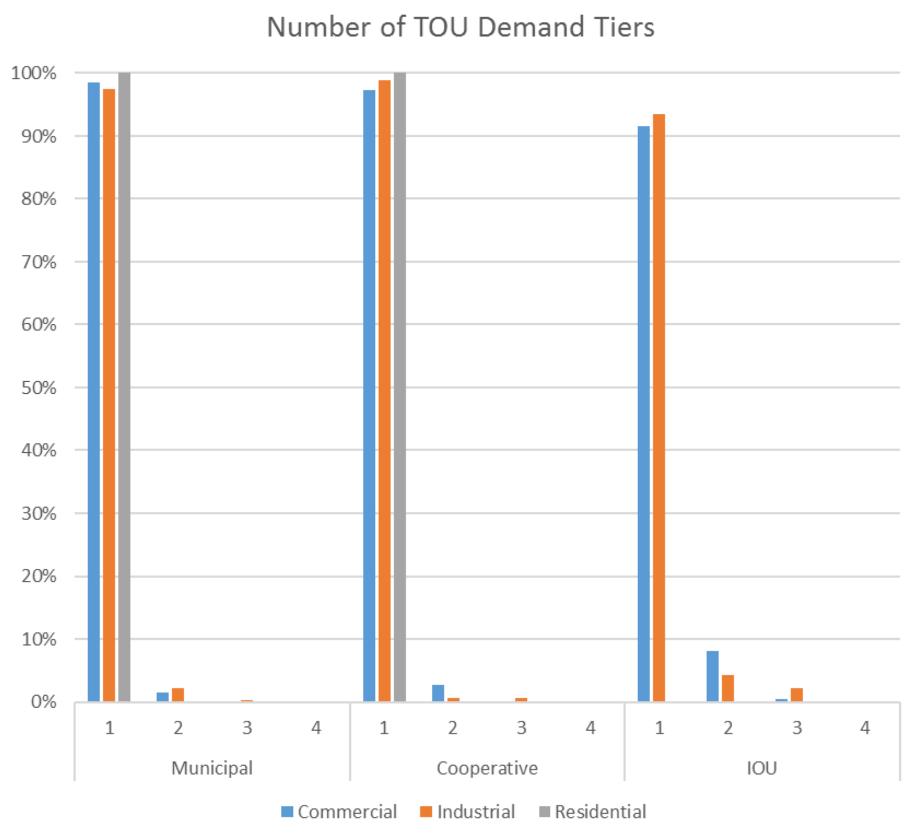
	Count	Mean	Median
Coop	51	$6.69	$6.40
Muni	43	$7.29	$6.87
IOU	34	$5.67	$6.01

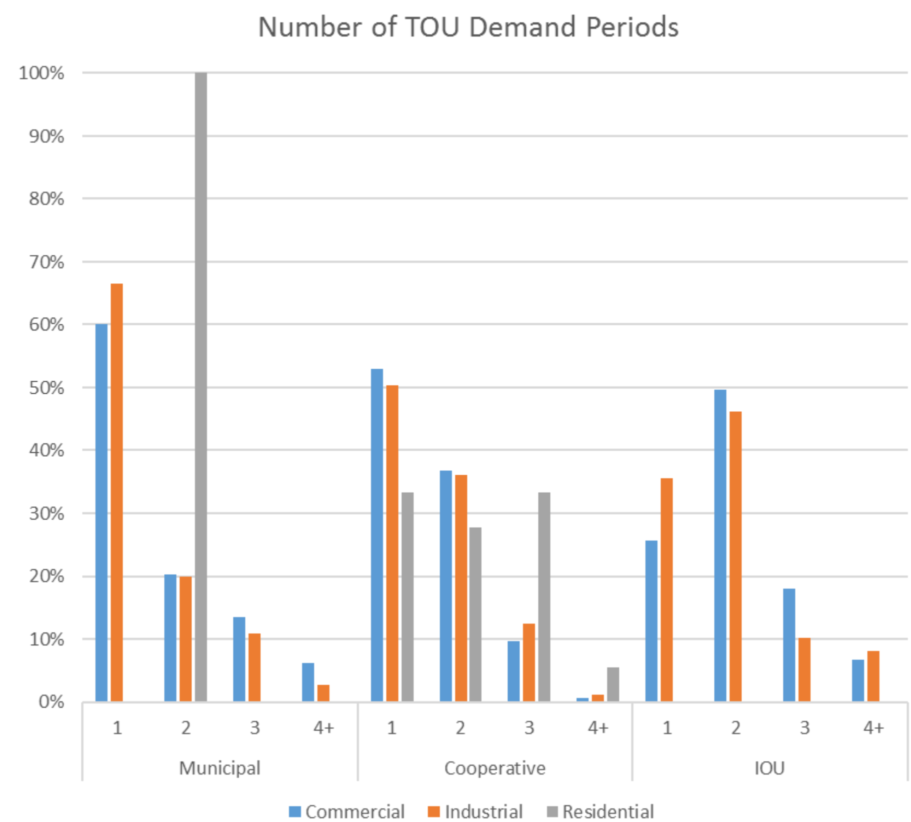
Time of Use Demand Charges

Time of use demand charges were the least popular rate structure in the dataset, with the most frequent occurrence in the industrial sector. Due to infrequent nature of this rate characteristic, a more detailed analysis was not performed.



Time of Use Demand Charge Details

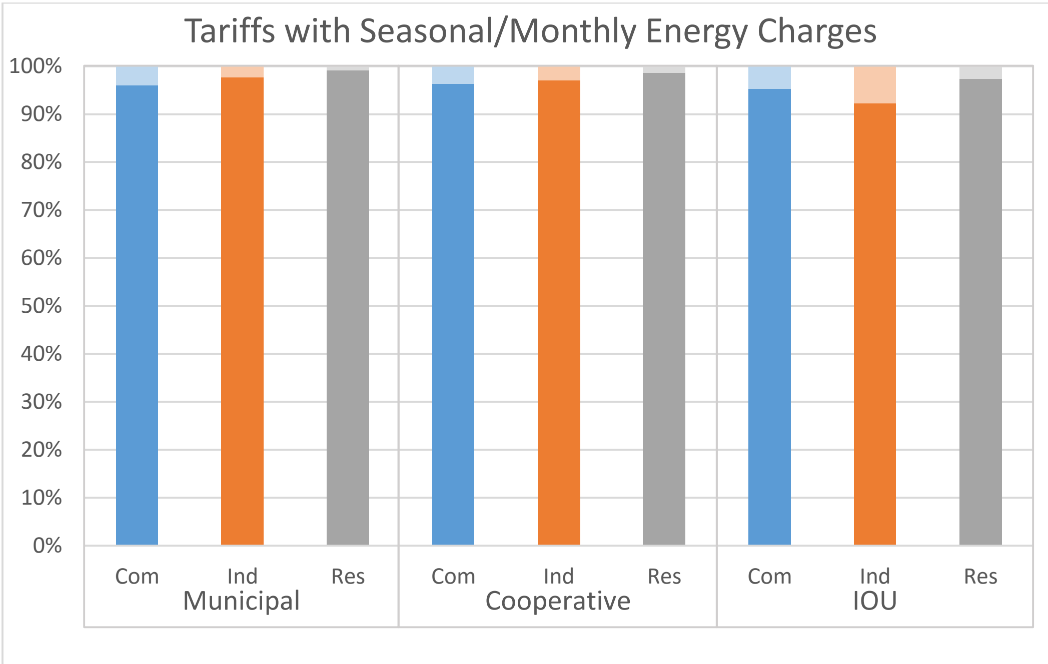




Seasonal/Monthly Energy Charge

While TOU demand charges are the least common, tariffs with seasonal/monthly energy charges are by far the most common. More than 95% of all sector/ownership combos (with the exception of Industrial/IOU) contained these rates. This is to be expected, as a kWh-based energy charge is the core volumetric rate that most mass market consumers associate with their electricity bill.

Of the few tariffs that did not include an energy charge, most were for specialty situations such as back-up power or unmetered rates. And while the lighting sector was not a focus of this analysis, roughly 85-95% of lighting tariffs did not have an energy charge.



There are more instances of multi-tier and multi-period energy charges than demand charges, although solid majorities of tariffs still consist of one year-round tier. The most obvious exception is in IOUs, where more than 50% of tariffs across sectors have at least 2 periods (with the most common in the form of a summer/winter rate structure).

A large minority of energy tariffs have a block structure. That is, energy prices for the first block of kWh consumed vary from prices for the second (or third or fourth) block consumed. These blocks vary by their width (i.e. how many kWh are in a block) and relative size (how much the price changes between blocks). A number of tariffs have a "free first" structure, where the first block of kWh are free (or presumably included in a fixed charge), and customers are only charged after consuming a certain quantity of electricity.

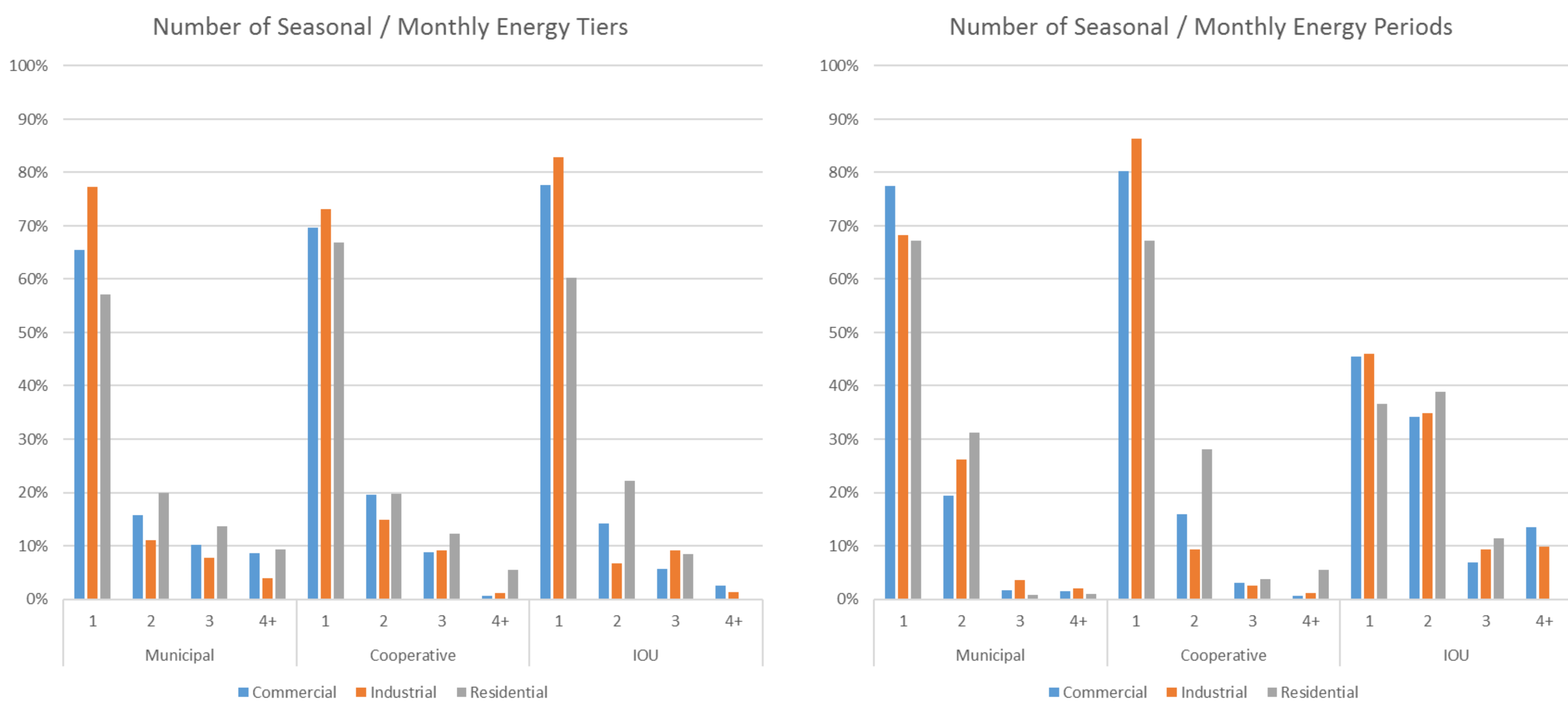
Of tariffs with a block structure, 83% were declining or "free first" declining, and only 14.5% were inclining or "free first" inclining (the balance had "free first" then flat structures). In the commercial and industrial sectors, declining block structurers were even more common, comprising roughly 95% of tariffs with a block structure. Residential tariffs had a less unbalanced split between declining and inclining block structures, but two-thirds of residential block tariffs were declining. Additionally, IOUs were more likely to have an inclining block structure than either cooperatives or municipal utilities.

For those tariffs with increases or decreases in the second block pricing, the change in pricing varied considerably. While some tariffs had relatively small (10%-20%) changes between tiers, others changed much more dramatically. Of the residential tariffs with inclining block structures, nearly

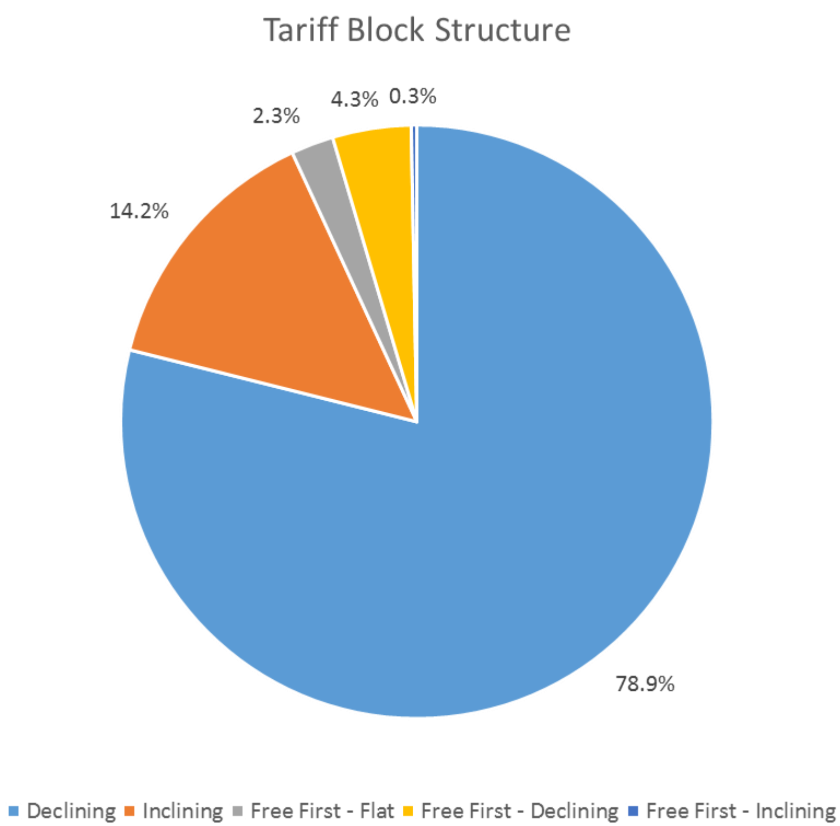
40% had at least a 25% increase in price between tiers, and nearly 25% had price increases in excess of 50%, and about 10% saw prices more than double, with increases over 100%.

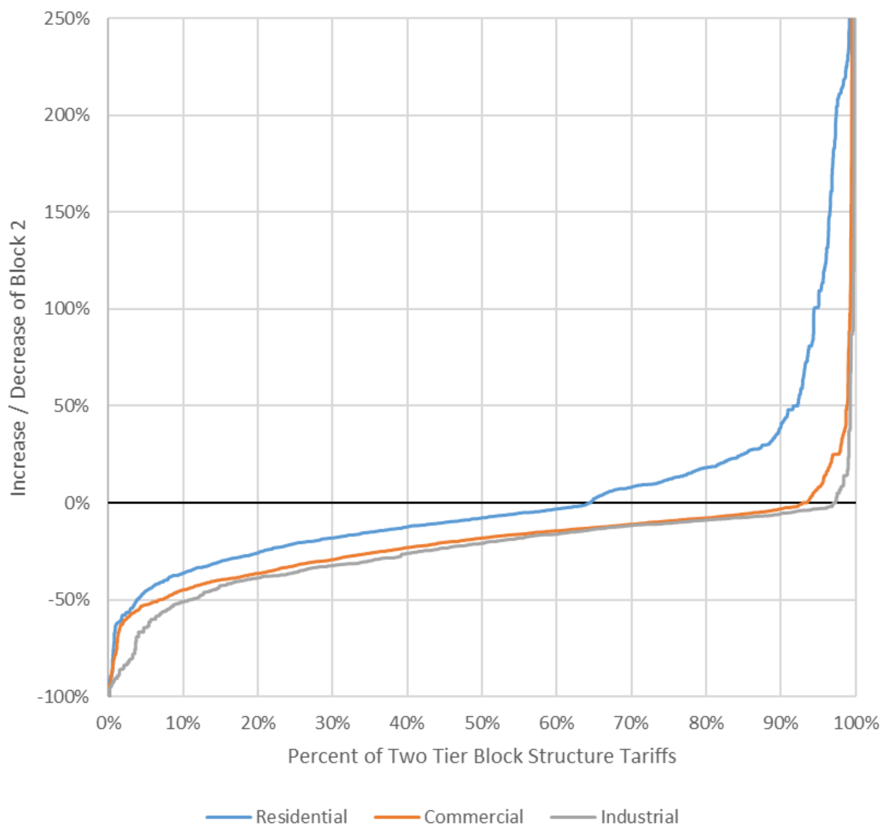
From an energy efficiency perspective, the prevalence of declining block structures is not ideal. By pricing the marginal kWh lower than the initial kWh, customers have less incentive to reduce their energy use. One potential explanation is that fixed customer charges might be higher in tariffs with declining block structures, but the data did not bear that out. While residential IOU tariffs with declining block structures did have a slightly higher median fixed charge, it was not substantially different than those with including block structures. An in contrast to this theory, both the median municipal and cooperative residential fixed charge were actually higher in the inclining block structures than in the declining block structures.

Seasonal / Monthly Energy Charge Details



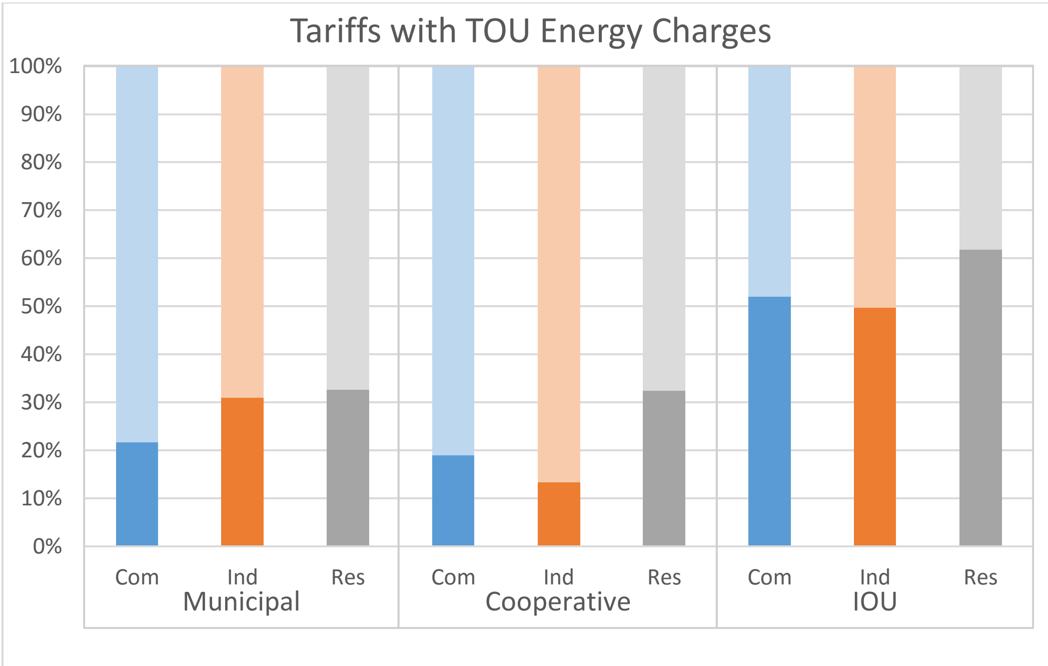
Seasonal / Monthly Energy Charge – Block Structure





Time of Use Energy Charge

Time of use (TOU) energy charges are relatively common in the tariff dataset. They occur most often in the residential sector across utility types, and among IOU tariffs across sectors. Anecdotally, the majority of TOU rates remain voluntary with an opt-in, and participation rates are not as high as the existence of the tariffs might indicate. That is, even though 60% of IOUs offer a residential TOU tariff, a substantially smaller percentage of customers are actually on those tariffs.[6]



TOU energy rates can also contain tiers and periods, leading to very complex rates.[7] While most TOU rates only have two periods (i.e. on-peak and off-peak), nearly 40% of IOU TOU tariffs have three or more periods. A peak/intermediate/off-peak rate structure is rather common.

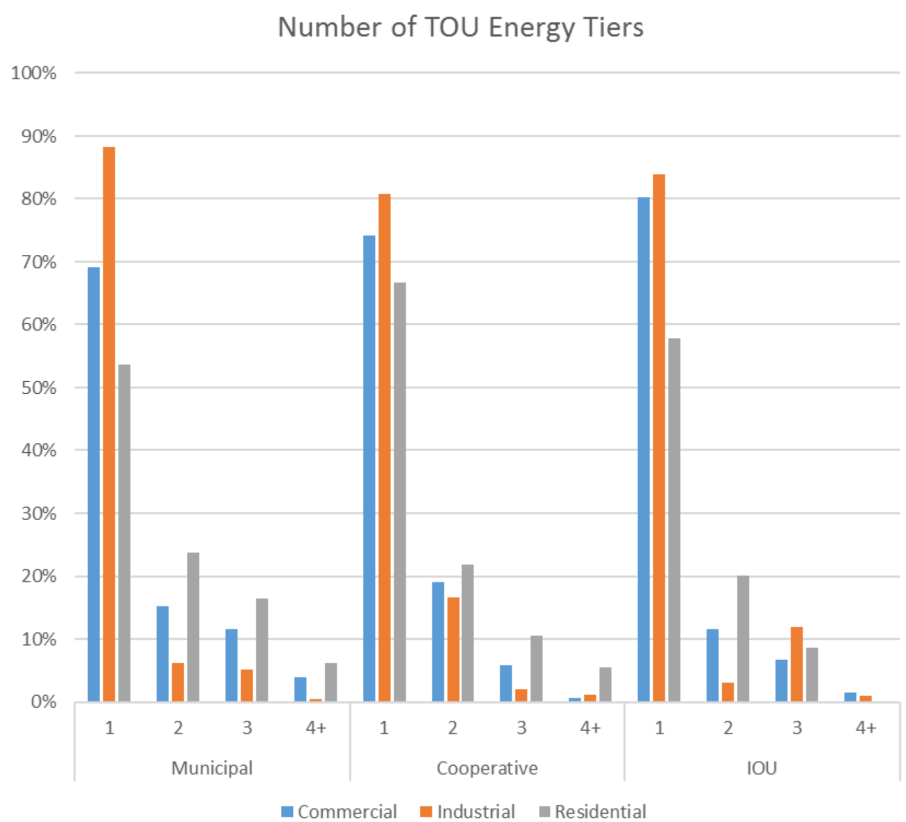
The relative cost of each period varies more between classes than it does between utility types. For TOU tariffs with two periods and one tier, the ratio between residential peak and off-peak rates began to separate from the commercial and industrial classes after the 40 percentile of the tariff's cumulative distribution, and stayed above of the other two sectors through the 95 percentile of the distribution. About 40% of residential tariffs had a peak/off-peak ratio of 2 or more (i.e. peak energy costing at least twice as much as off-peak energy), with about a quarter set at 3 or more.

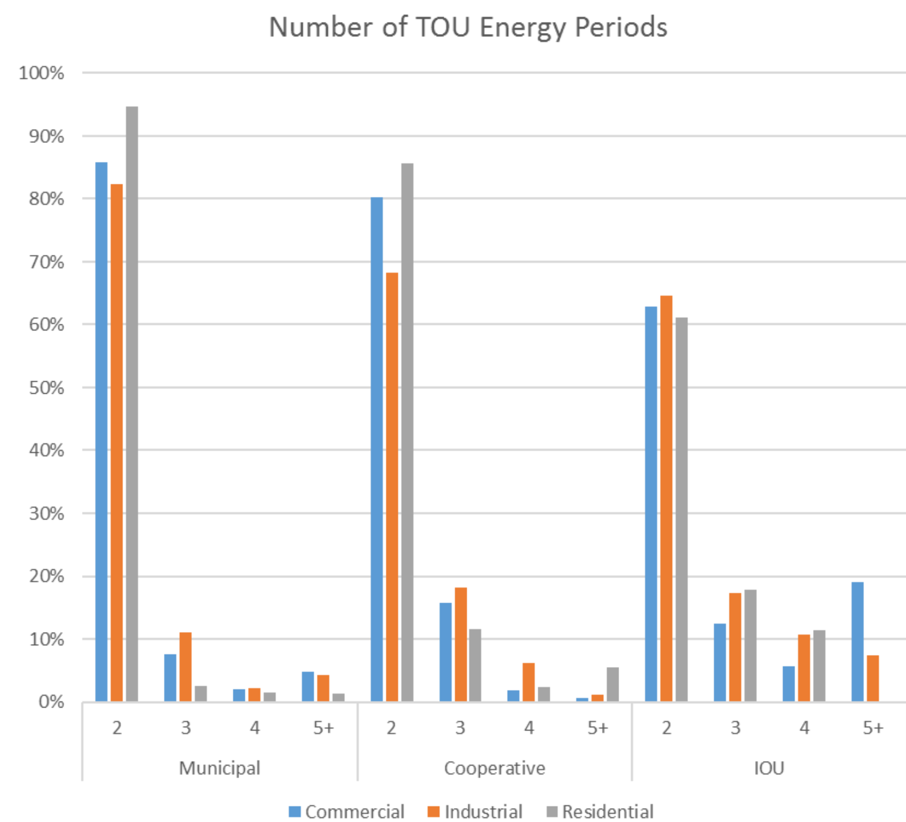
Commercial tariffs also separated from industrial tariffs at about the 60 percentile mark, but rejoined around the 95 percentile. Industrial customers maintained a very low ratio for the vast majority of their distribution, only to increase sharply for the last 10% of tariffs.

[6] As with demand charges, there is some movement in this area. Recent California rate settlements will move residential customers to a mandatory TOU rate in 2019.

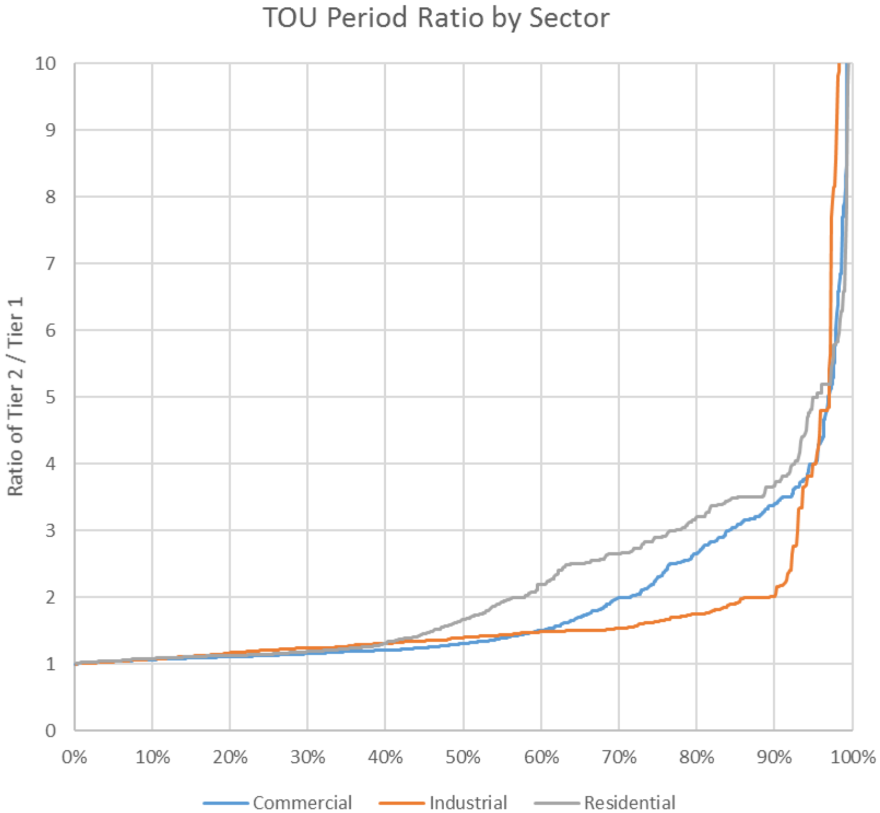
[7] Some California rates included 4 tiers *and* 4 periods, with costs for energy use changing seasonally, weekly, and hourly based on daily usage.

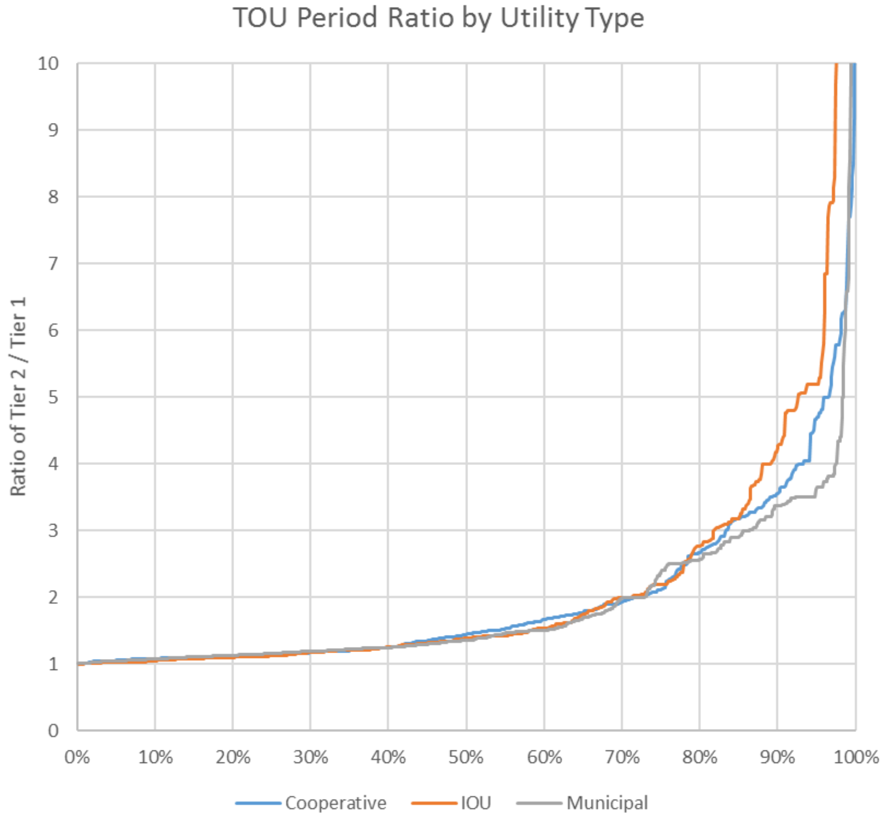
Time of Use Energy Charge Details





Time of Use Energy Charge Details





Concluding Thoughts

Rate design must balance a number of considerations, and be wary of both intended and unintended consequences. Good rate design allows a utility to recover its justified costs while enabling policy makers to incent behavior that benefits utility customers and society writ large. Bad rate design, on the other hand, may be punitive to a particular customer class or promote behavior that does not advance either the utility's bottom line or the value delivered to the customer.

In the OpenEI database, we see a huge variety of rate designs that have been implemented to balance and address these issues. Our analysis was not intended to claim which utilities are doing rate design correctly and which are not, but rather to see what, if any, trends emerge when analyzing a broad cross-section of different rate-making approaches. We are able to draw a few conclusions from this effort.

Broadly speaking and excluding outliers, IOUs are more likely than cooperative and municipal utilities to have rate structures that recover more costs from mass-market consumers (i.e. residential and commercial) through variable rates rather than through higher fixed charges. They are the most likely to utilize seasonal and TOU energy rates as well. For their industrial customers, IOUs tend to have higher fixed charges and lower demand rates than coops and munis. Finally, IOUs are the most likely to utilize an inclining block structure and to have more complex TOU rates.

Cooperatives have the highest distribution of residential fixed charges of the three utility types, and also the most likely to have the simplest one-tier, one-period energy rate structure. In other ways, they appeared very similar to municipal utilities (implementation of seasonal demand charges, low prevalence of TOU rates).

Rate design is as much a product of the regulatory environment as it is of the utility ownership model. While a broad-based analysis of tariffs in the OpenEI database is instructive to see some of these trends, state variations in policy tend to have an outsized impact on energy efficiency performance. The second analytical effort in the RDI sought to further explore this issue.

EIA FORM 861 ANALYSIS

The second major analysis performed by the Alliance for the RDI analyzed the Energy Information Administration's (EIA) Form 861. Form 861, the Annual Electric Power Industry Report, contains myriad details about the operational characteristics of electric utilities.[8] While the file format and data collected has evolved over the years, the data was substantially consistent enough to allow the Alliance to combine ten years of data (2005-2014) into one dataset for analysis.[9]

Form 861 contains operational data on sales, revenues, and customer counts, broken down by residential, commercial, industrial, and transportation sectors. The data also includes energy and demand savings and spending on utility energy efficiency (EE) and demand response (DR) programs, although some of the data collected in these areas changed through the years.[10] Finally, other information such as the existence of dynamic pricing and automated metering infrastructure is included to varying degrees through the years.

While many utilities include EE program data directly, several states have third-party implementers (such as NYSERDA and VEIC in New York and Vermont, respectively) that manage EE programs on behalf of the state's utilities. Fortunately, this data is also included in the forms, although it requires that data on EE spending and savings in states with third-party implementers are analyzed at the state level rather than the utility level.

In addition to the data found in EIA's forms, the Alliance analyzed information from the Edison Electric Institute (EEI), an electric IOU trade association, to gain some perspective on the macro trends facing the electric industry. These two datasets were not merged, but insights into industry capital investment helps inform the observations regarding utility revenues from electricity sales.

The Alliance incorporated additional policy considerations at the state level, including whether a state was restructured or partially-restructured, whether the state had an energy efficiency resource standard (EERS), whether revenue decoupling had been instituted, and what the state's average ACEEE Scorecard ranking was over the past five years.

As with the OpenEI analysis, the Alliance focused the Form 861 analysis on IOU, municipal, and cooperative utilities, while adding additional analysis on retail and wholesale power marketers as appropriate.

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[8] Form 861 data is available at https://www.eia.gov/electricity/data/eia861/

[9] EIA created a Short Form in 2012 that smaller utilities could fill out in lieu of the full Form 861. This data was merged back into the main dataset on an element-by-element basis as appropriate.

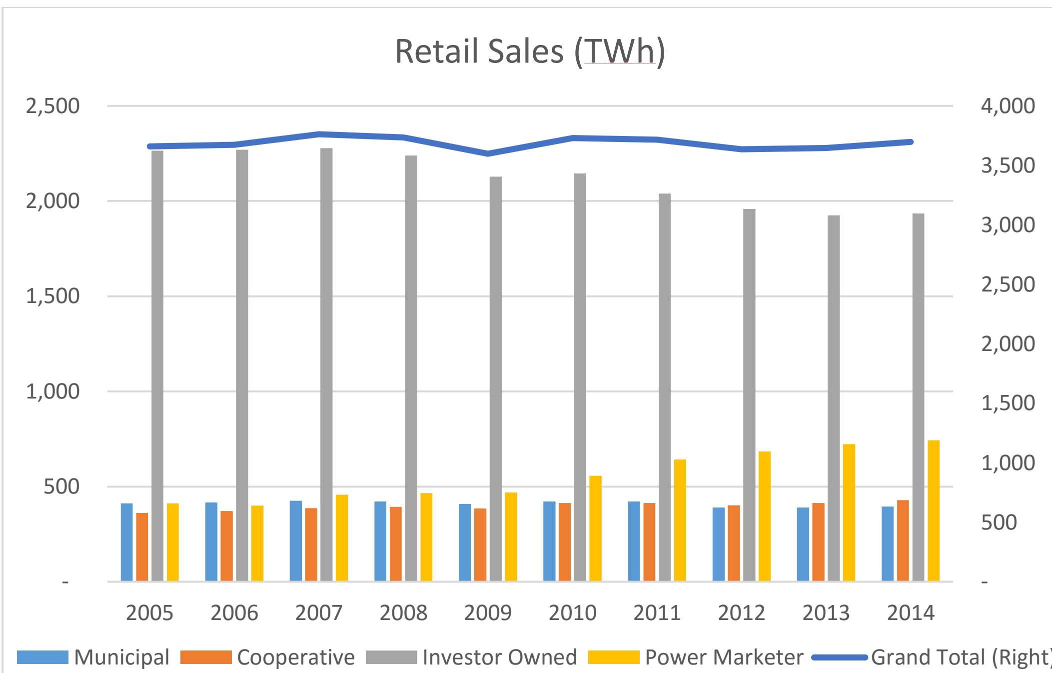
[10] The data is limited to utility-based programs and does not capture savings from ESCOs or other third-party business-to-business programs.

Macro Trends in the Electric Industry

To provide some context to the operational data found in Form 861, the Alliance first analyzed the trends in total sales and total revenue. Generally, total retail sales have been flat the past ten years, despite significant population growth and, despite the Great Recession, economic development. Sales in 2005 totaled 3,661 TWh, and were only slightly higher in 2014 at 3,764 TWh. While 2015 Form 861 data is not yet available, EIA has separately reported preliminary 2015 total sales at 3,725 TWh.[11] In other words, after decades of steady growth, the past decade has seen an increase in sales of only 1.75% in total, or about 0.17% per year.

Another observable trend is the erosion of IOU energy sales as customers shift toward retail power marketers. While utilities of course maintain a monopoly on the distribution of electricity, many states have restructured their electricity supply or enabled retail choice, and consumers are increasingly taking advantage of new options in the market. Bundled IOU sales (i.e. default or standard offer service) have fallen by 330 TWh, or about 15%, while power markers have picked up the slack and increased their aggregate sales by nearly 80% since 2005.

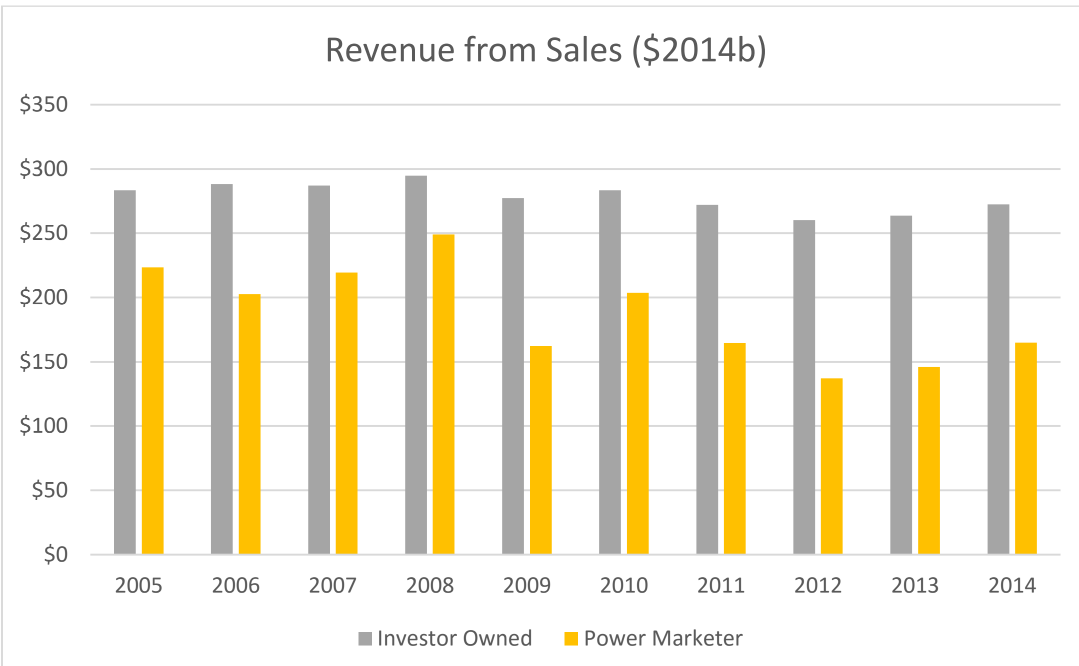
Cooperative electricity sales have defied the trend and have continued to realize small annual increases. Between 2005 and 2014, coop sales increased about 18.5%, at an annualized rate of 1.9%.



11 Electricity figures for 2015 are available at http://www.eia.gov/electricity/data/browser/

Turning to total revenue,[12] we see a somewhat different story for IOUs and power marketers. Because IOUs continue to receive revenue for delivering competitive supply, they are somewhat insulated from the reduction in their sales volumes shown earlier. This chart shows an incomplete picture of their regulated profits, as certain categories such as fuel costs are passed through as operational expenses on which utilities do not earn a return. Nonetheless, their total revenue in real terms has fallen from a peak of $294b in 2008 to $260b in 2012, before rebounding slightly to $272b in 2014. Total revenues for the entire electricity sector are down about 3% in real terms in 2015,[13] so it would be expected for IOUs to see some drop in their 2015 revenue as well.

Power marketers, on the other hand, have seen substantial volatility in their revenues over the past decade. Revenue peaked in 2008, with spikes in natural gas prices driving up the cost of electricity. But even as power marketer sales grew over the subsequent years, electricity prices continued to fall. Real revenue is down nearly 35% from $249b in 2008 to $165b in 2014, despite an increase in sales volume of 60% over the same time period. The steep and continued fall of natural gas prices have kept wholesale rates low, and the corresponding revenue figures reflect this.

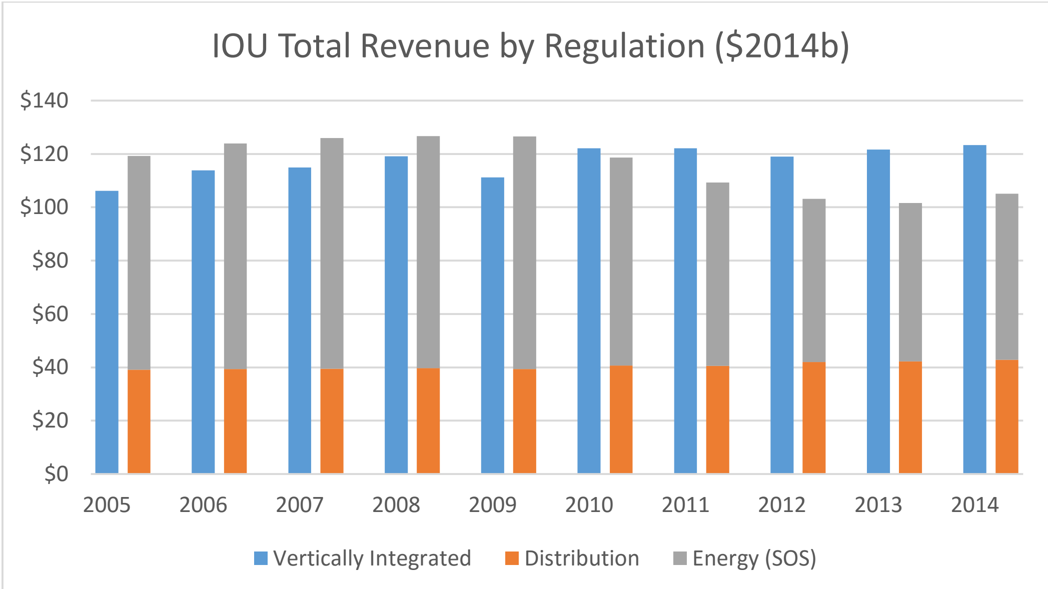


As mentioned above, profits for vertically integrated and restructured IOUs come from different sources. While both earn money on assets used to deliver power, restructured IOUs do not (generally) earn a return on power plant assets. Data in Form 861 is collected for bundled revenue (i.e. delivery plus energy for default or standard offer service) and for delivery-only revenue (revenue from customers in restructured states who use competitive suppliers). Through some manipulation of the data, we were able to extract the approximate revenues for both supply and distribution for distribution-only IOUs operating in restructured markets.[14]

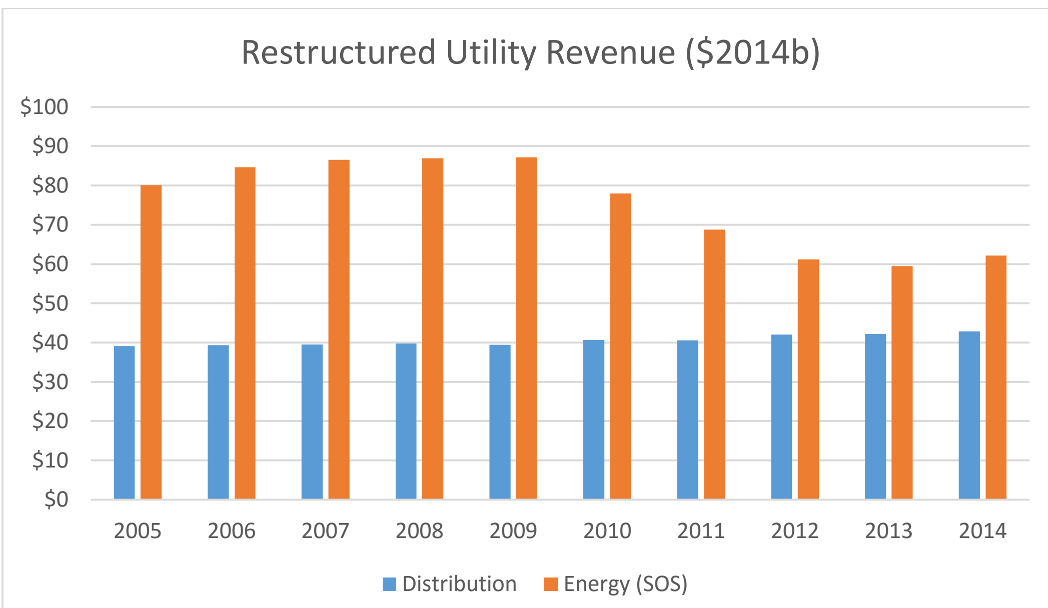
As seen below, revenue from vertically integrated utilities (blue columns) has grown in real terms over the past decade, although most of that growth took place between 2005 and 2010, with revenues flat between 2010 and 2014. On the other hand, total revenues from IOUs operating in

[12] All revenue figures were converted to $2014 using the GDP deflator unless otherwise noted.
[13] Supra note 11
[14] Generally, a distribution and SOS rate (including distribution) were calculated for each utility/class combination. The distribution rate was subtracted from the SOS rate to obtain a supply-only rate for the bundled product. Finally, the rates were converted back into revenue by multiplying by sales volumes, and distribution revenues were summed across distribution-only and bundled energy products.

restructured states (orange and grey columns) show that total revenues have fallen steeply since 2009, corresponding to the drop in electricity supply prices. But even this is not the whole story.



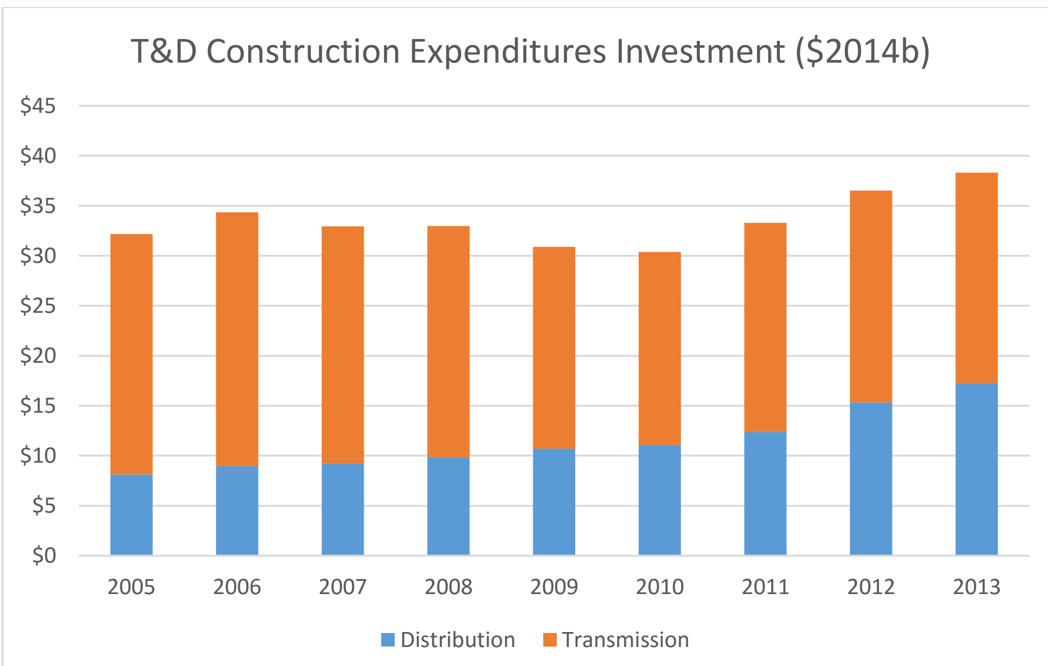
Because restructured utilities earn a return on their distribution assets, and bundled energy is typically treated as an operational expense pass-through, the revenue associated with the underlying distribution service is a more important financial metric. We see below that distribution revenue has grown slightly in real terms in 8 of the past 10 years, resulting in a 10-year real CAGR of 1.02%.



Of course, these figures are aggregated across the entire utility industry, and individual utilities might have seen higher or lower growth in their revenues. Nonetheless, from this data, it appears that the entity whose revenues are most affected by the precipitous drop in natural gas prices and wholesale electricity prices has been the competitive power marketer, not the regulated utility. It is little wonder that pure-play IPPs are struggling, while utility holding companies have sought out additional regulated revenues from distribution utilities to shore up their financial positions as their generating assets have been exposed to difficult market conditions.

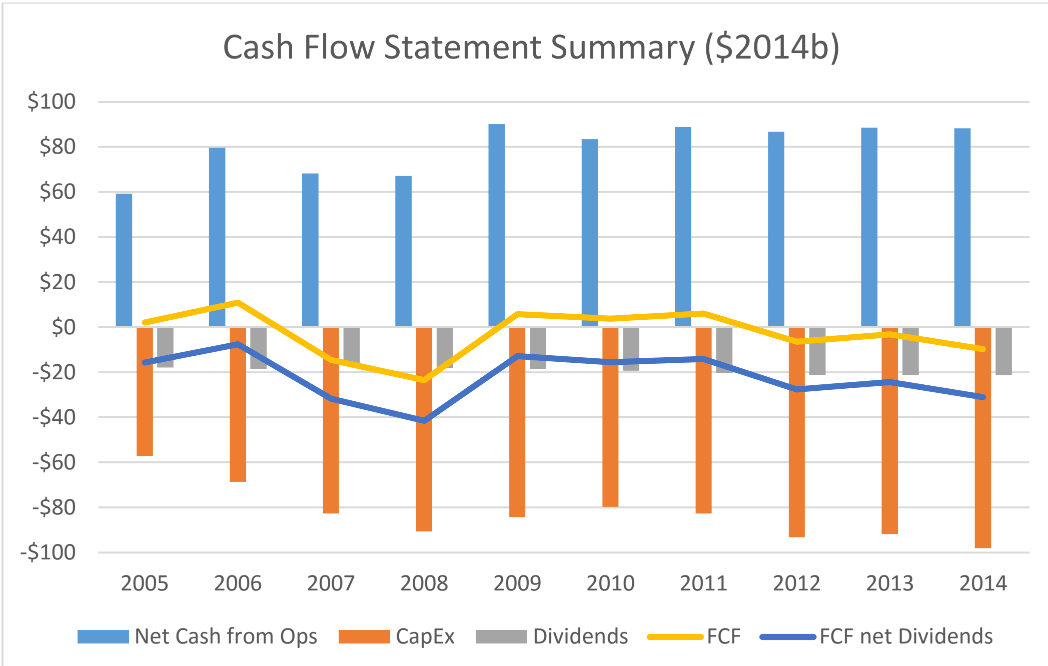
While Form 861 only contains data on revenues, other sources of information are available that aggregate utility infrastructure investments and industry cash flows. EEI consolidates financial statements across utilities and issues periodic reports on the financial health of the industry. The Alliance pulled EEI data on investment and cash flows to see how cash from operations (which is different than revenue as reported in Form 861) compared against investments.[15]

The first chart below shows transmission and distribution (T&D) construction expenditures. This category is broader than just capital expenditures, and includes costs such as labor. While the investment in transmission assets peaked in the mid-2000s and troughed in 2010, it has been on the rise in the past several years. Meanwhile, expenditures on distribution infrastructure has climbed continuously, and the pace has accelerated in the three most recent years of data (2011-2013). Distribution expenditures have more than doubled in real terms between 2005 and 2013, and almost approached the magnitude of transmission construction expenditures in 2013.



[15] EEI 2014 Financial Review, http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/finreview/Documents/FinancialReview_2014.pdf

Given rising expenditures and flat revenues, one can anticipate the following chart showing net cash from operations and free cash flow (FCF).[16] While FCF from operations before dividends (the typical manner in which FCF is reported by companies[17]) was positive until recently, FCF net of dividends has been consistently negative over the past decade. This deficit requires that utilities raise additional money from the debt and equity markets to continue to fund their operations.



Fortunately, the cost of debt has been at historic lows in recent years, and utility credit scores have remained solid the past several years, enabling access to financial markets at reasonable costs.[18] After a steep drop in market capitalization in 2008 (along with much of the rest of the economy), the EEI Market Capitalization Index has increased from just over $350b to about $630b in 2014.[19]

Advanced Metering Infrastructure Deployment

One of the major categories of distribution investment in the past several years has been advanced metering infrastructure (AMI). Form 861 contains information regarding AMI deployment on a utility-by-utility basis for more than 1,600 utilities. From this information, progress on AMI deployment can be tracked for a given utility over time, or the current state of AMI deployment can be summarized by state.

The Alliance took a snapshot of the deployment data, measured as AMI meters as a fraction of total meters, in 2014. Deployment data was summarized both by the count of utilities in a state, as well as by the total number of meters in a state. As we can see in the following charts, the apparent progress of AMI varies considerably depending if one is looking at total utilities or total meters.

When analyzing the data by total utilities, we see that in 30 states, more than half of utilities have implemented *zero* AMI meters. In fact, nearly 54% of all utilities who provided data for this section had installed no AMI meters, while 33% of utilities had installed at least 80% AMI meters. This is a very different picture when analyzing the data by the counts of meters. In this view, utilities who installed no AMI only controlled 27% of total meters, while utilities who installed at least 80% AMI

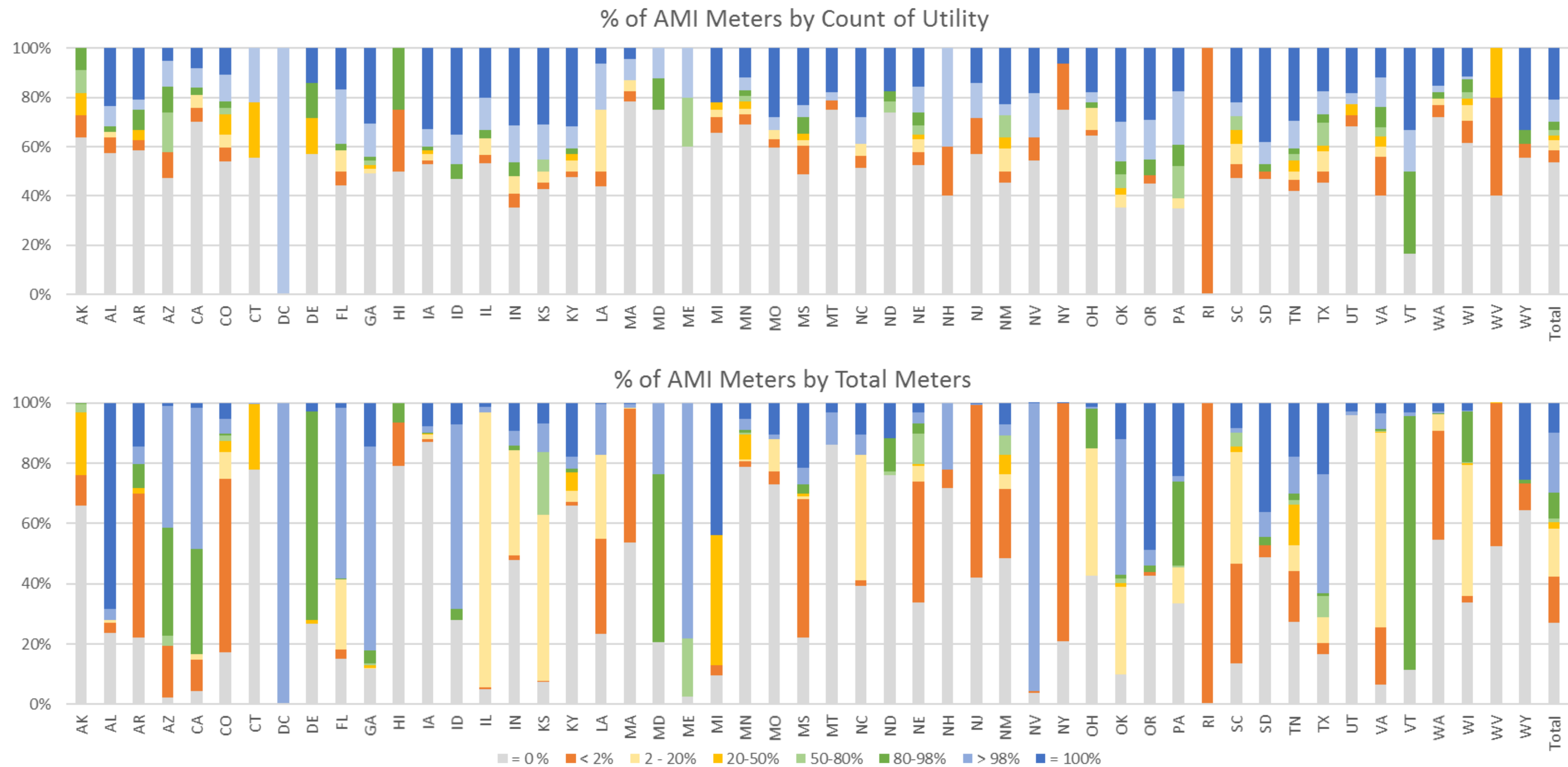
[16] Id p 18
[17] EEI recognizes this distinction, but reports FCF net of dividends citing the “utility industry’s strong tradition of dividend payments.” Id p 22.
[18] Id p 12 & 71
[19] Id p 69

controlled 38% of all meters. In other words, many small utilities are not installing AMI at all, and those who are installing AMI tend to serve larger customer populations.

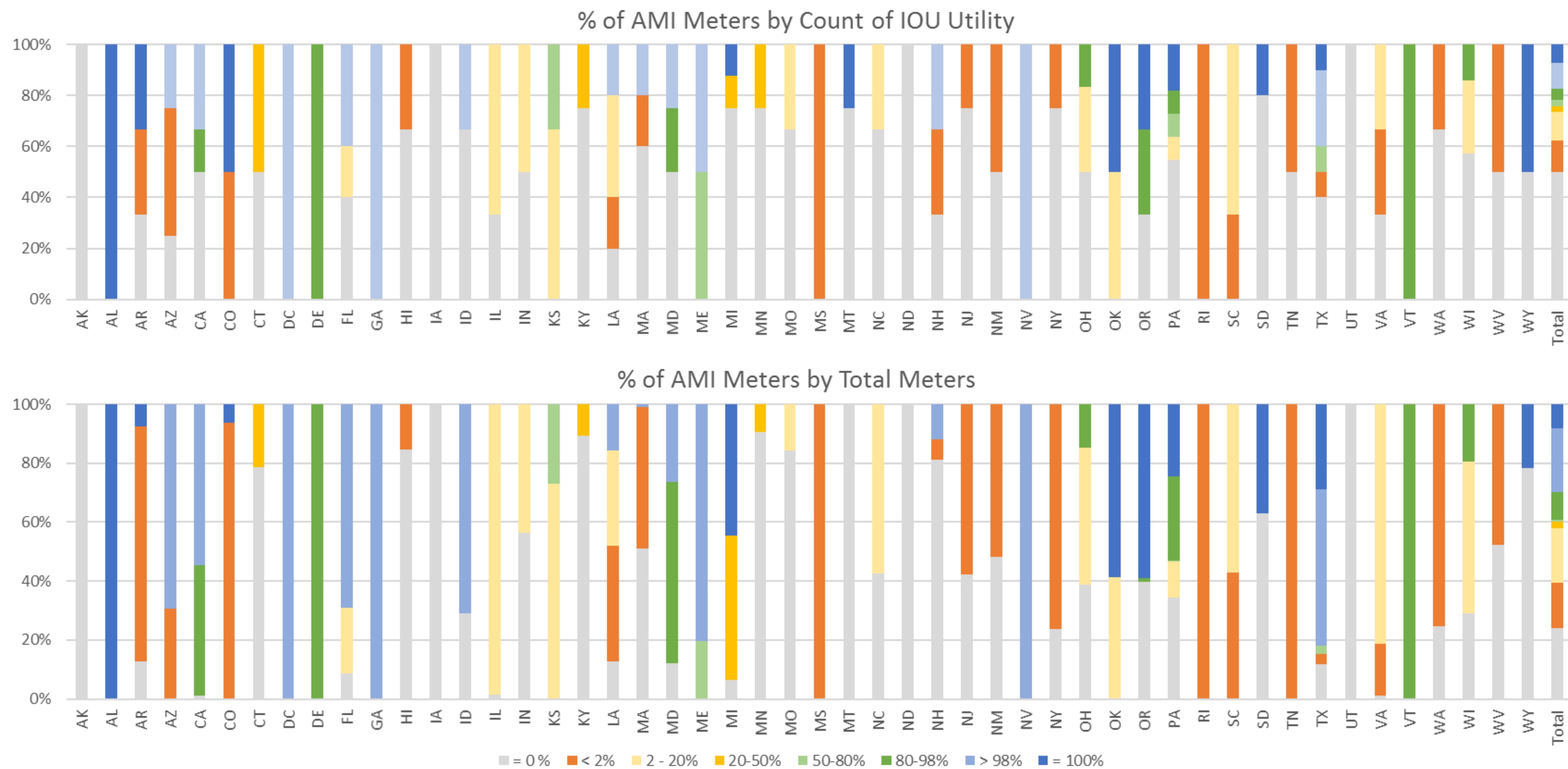
When isolating just IOU utilities, about half report zero AMI metering installations against 22% who have installed more than 80% AMI meters. Total meter installs are similar to the overall utility population, with IOUs that installed at least 80% AMI controlling 39% of all meters.

This has an interesting impact on rate design. Since rate design is more a function of a particular utility, rather than how many customers a utility has, the distribution of *utility* AMI penetration might be more relevant than the distribution of *utility meter* AMI penetration.

AMI Deployment for All Utilities



AMI Deployment for IOU Utilities

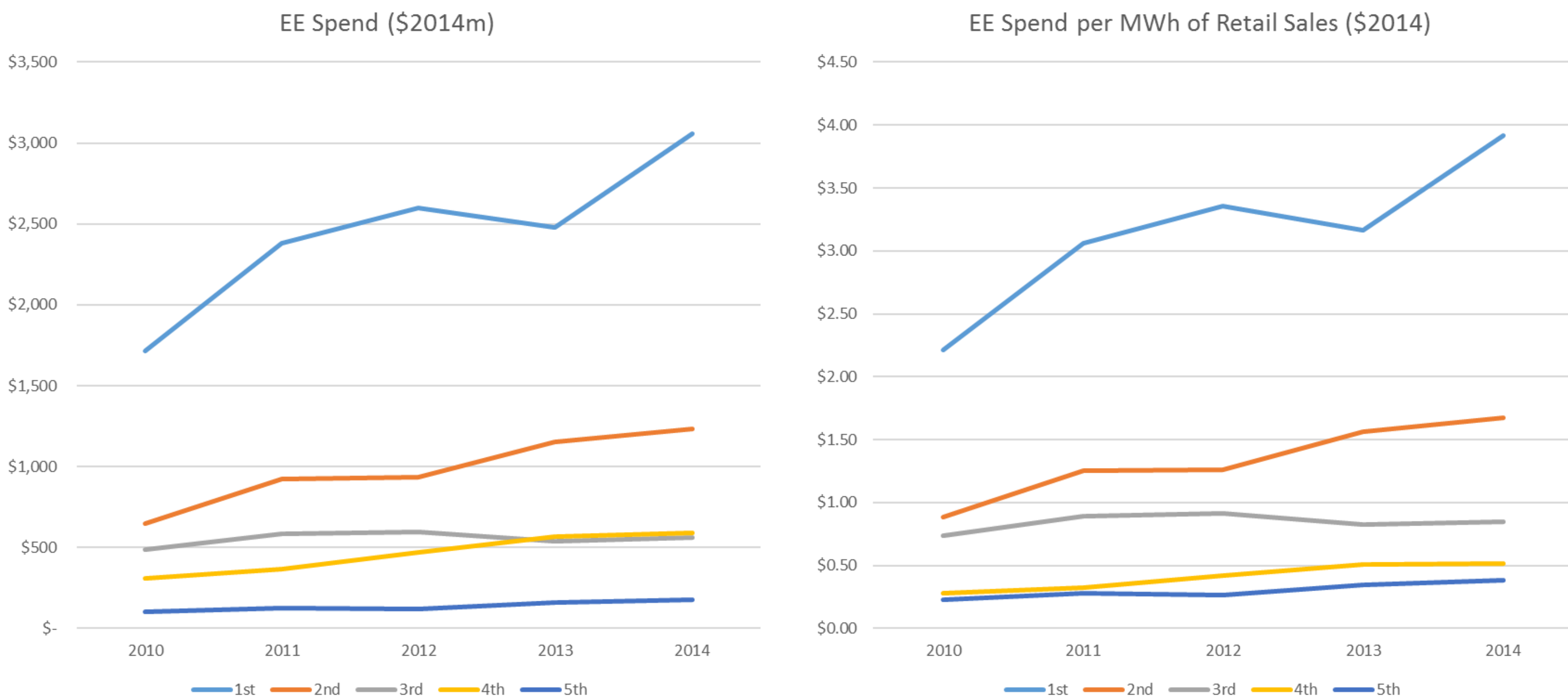


Utility Performance by ACEEE Scorecard Quintile Ranking

While operational data was readily comparable back to 2005, collected EE data varied over the years. In this analysis, the Alliance collated utility EE data back to 2010. While lifecycle savings data is available in more recent Form 861s, data from 2010-2012 did not include this information. As a result, the Alliance analyzed annual levels of EE savings and compared them across utilities for the years 2010-2014. As discussed in the earlier OpenEI narrative, an ACEEE Scorecard rank and quintile were calculated for each state and applied to this analysis.

The next page shows the absolute and relative levels of EE savings by quintile. Unsurprising, those utilities in the top quintile states spend more on EE programs than those in the bottom quintiles, both on an absolute level and a relative level. Notably, the 2nd quintile states have increased their spending in the past five years, but continued to be dwarfed in spend by the top states. Note that the right chart normalizes EE spending against total retail sales. This is not the same as the cost of energy saved, but more closely corresponds to what a customer might be charged per 1,000 kWh (roughly equal to the average monthly use of a residential customer) for their utility's EE programs.

EE Statistics by ACEEE Quintile



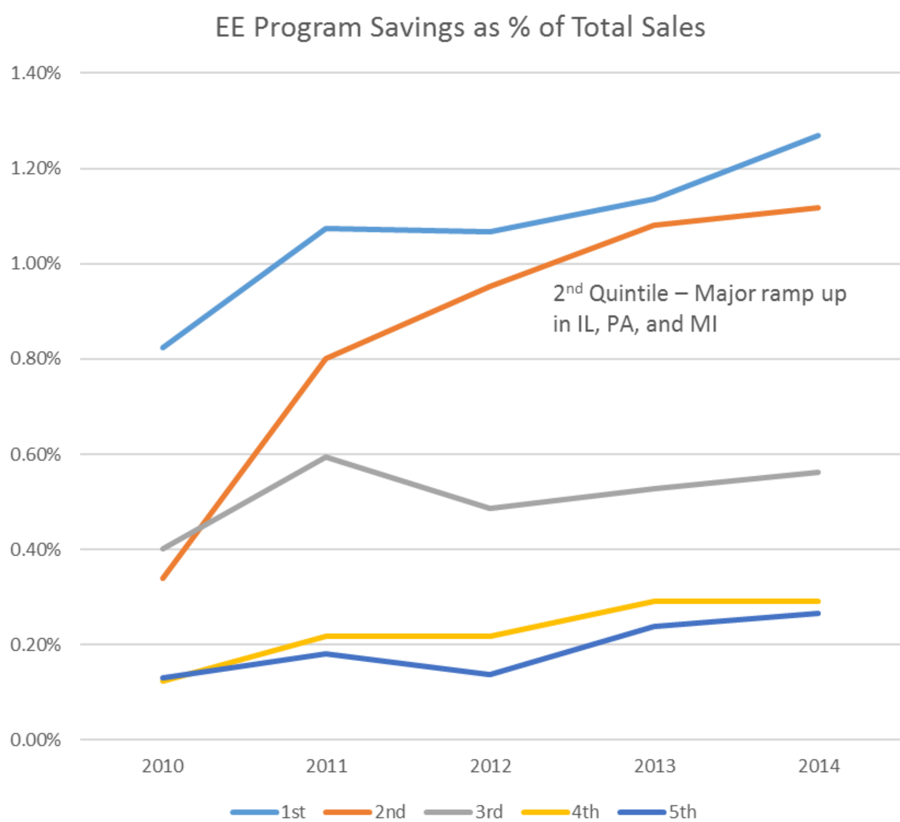
The follow two charts show the incremental savings that are attained, along with an approximation of the lifecycle cost per kWh saved.[20] Again, the trend in total savings is predictable: those states with higher spending on EE programs save more energy, and in turn tend to get a higher ranking in the ACEEE Scorecard. However, the magnitude of the difference between the quintiles is striking. The states in the top quintile saved an average of 5.6x more energy than the states in the bottom quintile. It is also notable that the 2nd quintile has dramatically increased its savings of late, with increases in three large states – IL, PA, and MI – driving this quintile's performance. It is a testament that when policies align, EE programs – and savings – can be ramped up quickly.

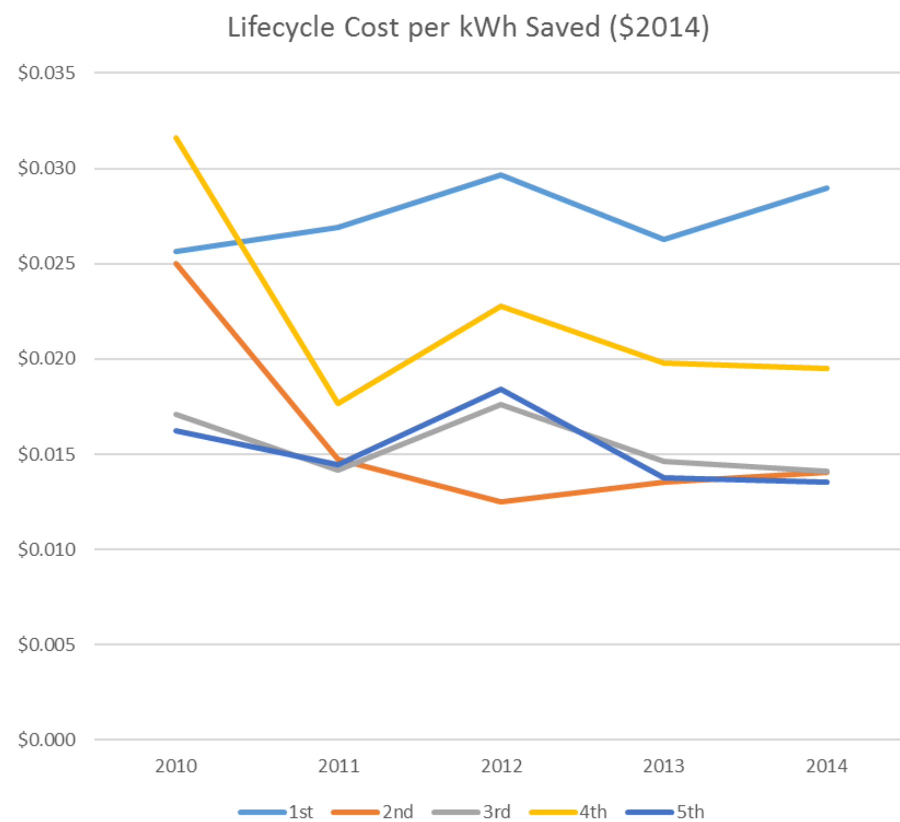
The lifecycle cost data on the right chart is also instructive. While it is true that the cost per lifecycle kWh saved in the top quintile is higher than the others, it is also true that the states in the top quintile have been running EE programs for longer and some of the initial inexpensive "low handing fruit" such as lighting retrofits has already been captured. Further, even in the most expensive states, the cost per avoided kWh in this data is less than 3 ₵ /kWh. Given that electricity rates are well in excess of this – even for low-cost states – efficiency clearly costs less than the alternative of purchasing more supply and building more infrastructure to deliver that supply.

Another observation can be made that shows the impact of policy. The cost per lifecycle kWh saved in the lowest quintile is roughly the same as that in the 2nd quintile at 1.5 ₵ /kWh, but the 2nd quintile outperformed the bottom quintile by 320% in 2014 savings. Clearly, the cost of running EE programs is not a fundamental limiting factor, so something else must be driving the differences.

[20] An assumption was made that the average useful life of a utility's 2013-2014 program's measures (which were included in the data from those years) could be applied to its 2010-2012 program measures.

EE Statistics by ACEEE Quintile





Policy Impacts on Energy Efficiency Savings

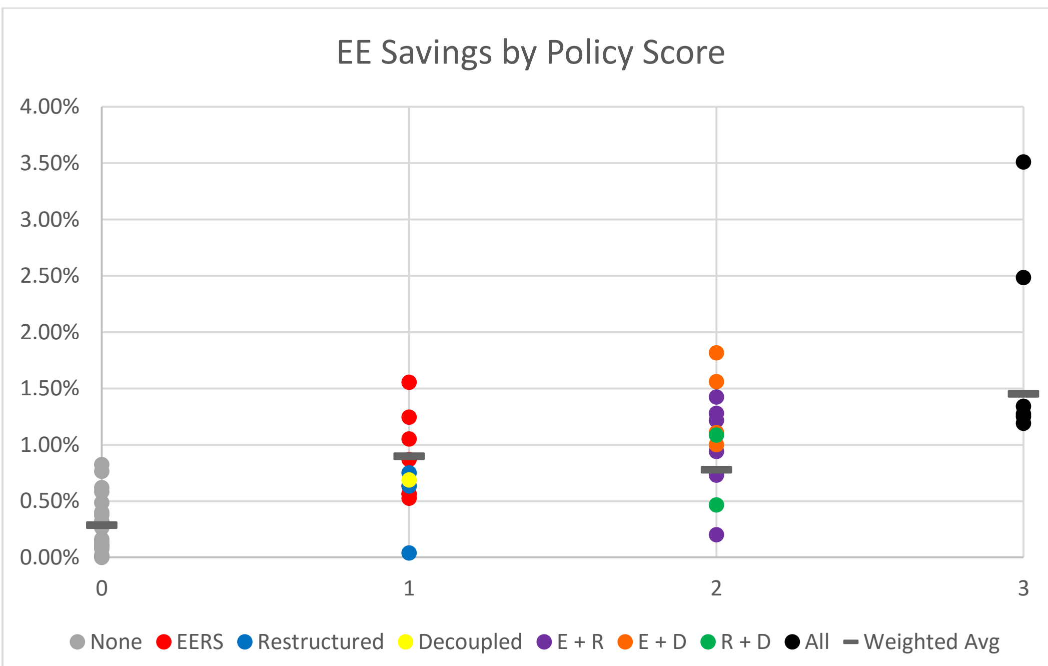
To investigate this observation more deeply, the Alliance considered what policy drivers might be impacting EE program savings. Three policies were considered: utility regulatory structure (i.e. vertically integrated or restructured), EERS policies, and revenue decoupling. Each of these policies was applied at the state level, even if in certain states only some utilities are decoupled or under an EERS.

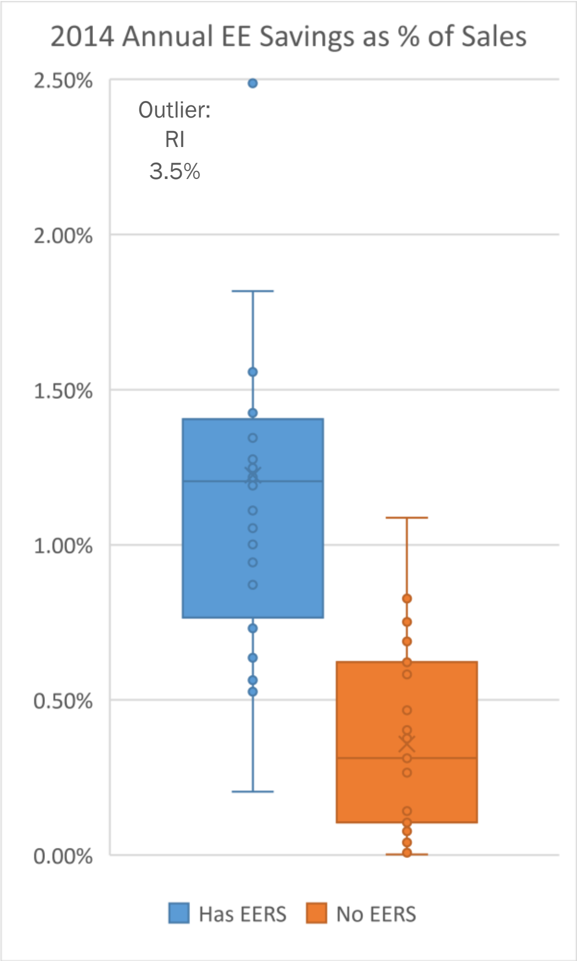
The results are intuitive, but the magnitude of the effect is notable. States with EERS and revenue decoupling have much higher range of average savings than those without these policies. There was a weak relationship in the data between regulatory structure and EE savings, with competitive supply states having a slight edge in their savings distribution.

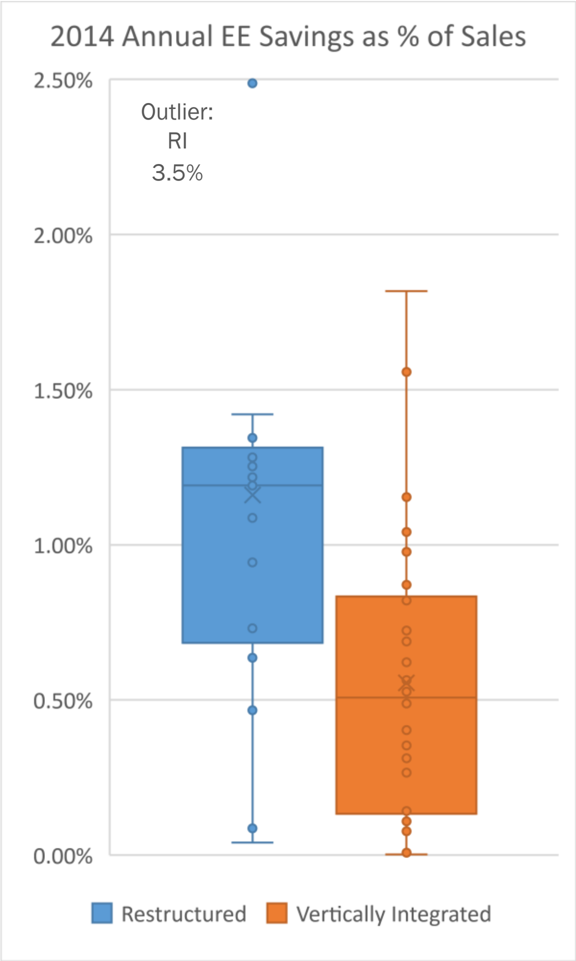
The following table summarizes the results of the policy impacts on EE program savings, and the box-and-whisker graphs on the following page shows the distribution of savings for each policy.

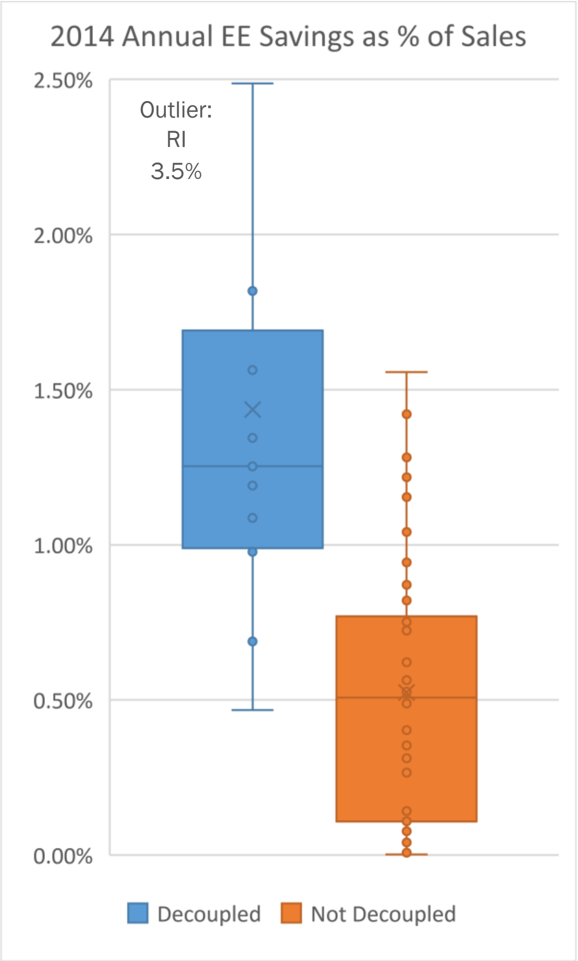
Policy	Has EERS	Is Decoupled	Is Restructured
Number of States	24	13	17
Average savings with policy	1.22%	1.44%	1.16%
Average savings without policy	0.36%	0.52%	0.55%
Difference	**0.86%**	**0.92%**	**0.61%**

After the impact of each individual policy was determined, we looked to see if there were cumulative benefits of multiple policies. The relationship is somewhat weak, but generally there appears to be a benefit of combining policies.




2014 Annual EE Savings as % of Sales
2.50%
2.00%
1.50%
1.00%
0.50%
0.00%
Outlier:
RI
3.5%
Has EERS
No EERS


2014 Annual EE Savings as % of Sales
2.50%
2.00%
1.50%
1.00%
0.50%
0.00%
Outlier:
RI
3.5%
Restructured
Vertically Integrated


2014 Annual EE Savings as % of Sales
2.50%
2.00%
1.50%
1.00%
0.50%
0.00%
Outlier:
RI
3.5%
Decoupled
Not Decoupled

While the results of the individual policies and even simple combinations of policies are interesting, a more robust analysis can be performed through a regression analysis. Savings from 2013 and 2014 were regressed on binary variables representing each policy, with the results indicating the strength and importance of each policy's contribution to total savings. As foreshadowed from the individual policy charts, the results show that states with an EERS and decoupling are statistically more likely to have higher savings than those without, while restructuring was not statistically significant.

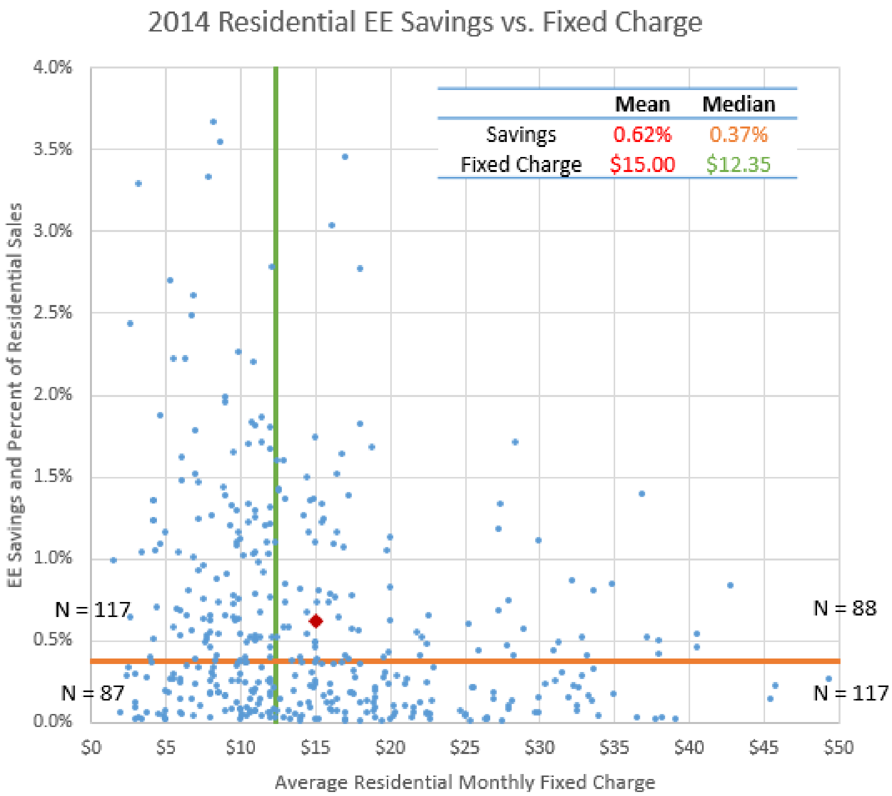
Regression Results	Coefficients	Standard Error	t Stat	P-value
Intercept	0.264%	0.055%	4.757	0.000
EERS	0.627%	0.085%	7.416	0.000
Restructured	0.094%	0.090%	1.045	0.298
Decouple	0.505%	0.097%	5.178	0.000

The regression had an R^2 value of 0.59, indicating that roughly 60% of the variation between the states' EE savings could be attributed to the variables in the regression. The results show that all else equal, the presence of an EERS policy will add 0.63% annual savings to a state, while revenue decoupling will add 0.51% annual savings.

Residential EE Savings Cross-Analysis with OpenEI Database

While the information contained in Form 861 and the OpenEI tariff database are very different, both databases use the same identifier for a given utility. As mentioned earlier, the tariff database does not contain participation levels, so it is difficult to draw too many conclusions about the general existence of tariffs and the savings from those utilities. However, a narrower analysis of residential fixed charges and residential EE savings was conduction to determine if any relationship existed.

To perform this analysis, the average residential fixed charge for the 409 utilities that reported residential energy savings was appended to the Form 861 data set, and a scatter plot of 2014 residential EE program savings and average fixed charge was generated. The data show that occurrences of higher savings are skewed toward utilities with lower fixed charges. Of 205 utilities with residential EE savings above the median value, 57% had fixed charges below the median value. And of the 97 utilities with greater than 1% annual residential savings, 65% had fixed charges below the median value.



Concluding Thoughts

The utility industry is moving into unprecedented territory. Sales growth has slowed from historic norms, and in some states is negative. Infrastructure investments on the distribution side are increasing. And while revenues from regulated activities have grown, they have grown slowly and have not kept pace with cash outlays. It is against this backdrop that utilities, customers, and commissioners must plot a path forward.

EIA Form 861 reveals a number of expected, and perhaps unexpected, results regarding utility EE programs. Utilities in states with a high ACEEE Scorecard ranking tend to spend more money on EE programs and realize correspondingly higher savings from those programs. Top tier states save more than 5 times as much energy as a percentage of sales than bottom tier states, while program spending remains substantially lower than the alternative cost of supply.

Policies matter in terms of EE performance. Using a regression analysis, the data in Form 861 demonstrates that EERS and rate decoupling policies are statistically significant drivers of energy savings, and that restructuring, while proving a small benefit for energy savings, it not statistically significant. Together, these policies contribute about 60% of the expected variation between states.

Rate design is also important, although the direct linkage is harder to analyze with this dataset. To gain additional insight to a subset of this broader question, the average fixed charge for a residential customer from the OpenEI database was merged with the Form 861 performance data. There exists a correlation between lower fixed charges and higher residential energy efficiency performance, although without detailed participation figures it is difficult to establish a level of causation directly from this data. That said, there is substantial academic literature that shows that all else equal, higher fixed charges tend to reduce motivations for consumers to save energy. This leads us into the third part of our background research.

Review of Literature

In addition to performing the technical analyses that were described above, the Alliance reviewed roughly three dozen academic research papers, regulatory orders, and policy whitepapers from a variety of nationally recognized experts in rate design and energy efficiency policy. We further reviewed numerous articles from popular industry websites such as E&ENews, Greentech Media, Utility Dive and regional newspapers following local stories. This section provides a short overview of several papers that the Alliance found particularly illuminating on the topic at hand. Appendix B includes a list of sources for all the research papers that were reviewed as part of this effort.

Smart Rate Design for a Smart Future

Lazar, J., and W. Gonzalez. 2015. Regulatory Assistance Project.

Jim Lazar and Wilson Gonzalez wrote *Smart Rate Design for a Smart Future* to update the basic principles of rate design that were developed nearly fifty years ago to be more compatible with the current structure of and challenges facing the modern electricity industry. Lazar and Gonzalez recognize that rate design is critically important in motivating customer and utility decisions, and that economically efficient prices underpin good rate design. They note that one estimate ascribes a 15% difference in energy usage between a progressive and regressive rate design.

Lazar and Gonzalez develop three principles for modern rate design that refresh the classic Bonbright[21] principles in a world with high and increasing DER penetration and customer-sited backup supply.

- **Principle 1:** A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- **Principle 2:** Customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume.
- **Principle 3:** Customers who supply power to the grid should be fairly compensated for the full value of the power they supply.

Applying these principles leads the authors towards time-varying rates and away from high fixed charge structures. Time differentiated pricing helps more equitably recover costs and send efficient price signals to consumers to help minimize overall system costs. Further, the authors suggest that while demand charges based on non-coincident peaks were necessary due to technical limitations before AMI was deployed, they fail to properly allocate costs based on system use. The general conclusion of the paper is that time-varying costs are the best way to recover costs and to meet policy objectives such as energy efficiency.

Lazar and Gonzalez offer a sample rate structure for residential customers that reflect their principles. Note the small customer charge that only recovers basic customer-related charges and not any system charges. A small demand charge based on the final line transformer is included, but the bulk of the revenue is collected through time-varying energy rates along with a critical peak pricing component.

Rate Element	Based On the Cost Of	Illustrative Rate
Customer Charge	Service Drop, Billing, and Collection Only	$4.00/month
Transformer Charge	Final Line Transformer	$1/kVA/month
Off-Peak Energy	Baseload Resources + Transmission and Distribution	$.07/kWh
Mid-Peak Energy	Baseload + Intermediate Resources + T&D	$.09/kWh
On-Peak Energy	Baseload, Intermediate, and Peaking Resources + T&D	$.14/kWh
Critical Peak Energy (or PTR)	Demand Response Resources	$.74/kWh

[21] Bonbright, J.C. 1961. "Principles of Public Utility Rates."

Designing a New Utility Business Model? Better Understand the Traditional One First

Kihm, S., J. Barrett, and C.J. Bell. 2016. American Council for an Energy-Efficient Economy.

Moving Toward Value in Utility Compensation. Part One – Revenue and Profit.

Kihm, S., R. Lehr, S. Aggarwal, and E. Burgess. 2015. Seventhwave, Western Grid Group, America's Power Plan, Utility of the Future Center.

This pair of reports, co-authored by Steve Kihm, discusses the financial drivers that underpin utility management decisions, and concludes that shareholder value should be the ultimate arbiter of the financial success of a utility company. The first report (ACEEE) focuses on a commonly misunderstood motivator of utility investments. The second paper (Seventhwave) asks how regulators should use this motivating factor to achieve policy goals.

In the ACEEE report, the authors use data from financial markets to corroborate the findings that when utilities' returns on equity exceed their cost of equity, they can create shareholder value through investments. This is not a problem per se, but it does create an incentive for utilities to invest, as each dollar invested will increase shareholder value. The question for policy makers is how to best create incentive structures that align the utility's desire to invest with consumers' and society's desire for positive outcomes.

In the Seventhwave report, Kihm et al. use the basic tenets of corporate finance to demonstrate that a utility has an incentive to invest when their expected return on equity exceeds their cost of equity. Using recent rate cases, the authors determine that a typical return on equity is around 10%. Using book-to-value ratios, they further determine that a typical utility cost of equity is about 7.5%. While the spread between these two values is currently positive, this was not always the case. During a period from the mid-1960s through 1980, the return on equity was less than the cost of equity, and by investing in infrastructure during this time, utility stocks lost billions of dollars' worth of shareholder value.

However, in the current regulatory and financing regime, the positive spread between the return on and cost of equity results in a scenario where utilities create shareholder value every time they deploy capital. Further, they typically earn the same return regardless of the investment's value to customers or to society. Finally, rate cases tend to focus on recovering costs that are historic in nature, rather than looking at what future value will be delivered through new investments.

Given this, the authors discuss what utility commissioners should do. They do not suggest eroding the return on equity to the point where utilities have no incentive to invest, but rather to structure their earning power in a way that aligns with other policy interests that the utility customers may have. The authors ask two key questions:

- What values and services do we want our electric system to provide?
- How can we improve the incentives currently provided by regulation to get more of what we want from electric utilities?

Kihm et al. suggest that regulators have direct control over the return on equity that they allow utilities to earn (through rate cases), but are only able to influence the cost of that equity (set by the financial markets). In setting the return on equity, the authors caution commissioners to pay attention to the magnitude of shareholder value created in dollars, rather than to the return on equity in percentages.[22] They further suggest that performance-based incentives are a good way to

[22] This is an important distinction, because the value created from a large return on a small investment (e.g. a 10% return on a $100,000 investment) may be smaller than the value created from a small return on a large investment (e.g. a 2% return on a $1,000,000).

align the incentive for utilities to invest in ways that provide benefits to consumers and society in additional to bringing value to shareholders.

They also suggest that while commissioners cannot set the cost of equity that the financial market requires for investment, they can influence the cost by either increasing or decreasing the perceived riskiness of the utility's investments. In one example of a utility choosing to invest between a coal plant, a gas plant, and a wind farm, the authors suggest that a commission could pre-approve recovery of the costs associated with the wind farm within a certain deviation from the budgeted costs, while holding the costs associated with the coal plant to a full prudency review. In this instance, the investment in the wind farm is de-risked relative to the investment in the coal plant.

The concluding thought on this pair of papers is best expressed through one of their quotes:

> For investors, it's all about value, not profit. If utilities can create shareholder value by investing in certain assets, but can only tread water in a financial sense if they invest in others, utilities will seek out the value-creating resources. This takes us back to Kahn. It is not appropriate that ***all utilities*** earn returns in excess of the cost of equity on ***all investments***. Our goal should be to allow such returns **only on investments that help to deliver value to customers and achieve public policy objectives**. (Seventhwave, p 17, emphasis in original)

Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future

Corneli, S., and S. Kihm. 2015. *Future Electric Utility Series*. Lawrence Berkeley National Laboratory. Rep. no. 1

The first in the six-part Lawrence Berkeley National Lab "Future Electric Utility Series", this report from Steve Corneli and Steve Kihm discusses the pressures of technological innovation and deployment of distributed energy resources (DER) on the traditional monopoly structure of utility companies. The authors examine why the traditional model might be breaking down, and whether or not a regulated monopoly continues to be the socially optimal manner in which to deliver certain electricity services.

Corneli and Kihm discuss the economic theory behind natural monopoly regulation of utility companies. In the historic construct, granting utilities service territory monopolies produced a societally optimal outcome as the economies of scope enabled a single entity to serve the entire customer base at a lower cost than multiple firms serving the market. But as the cost of DERs has fallen, it begs a question whether this continues to be the case for all products (e.g. energy, capacity, integration services) that a distribution utility currently provides its customers. If the answer is yes, then society is best served by continuing the monopoly supply of these services. However, if the answer is no, then enabling competition for some of the products may produce better outcomes.

The authors discuss two hypothetical worlds in 2030 in which the challenges of increasing DER penetration must be addressed by regulators, with each author proposing an alternative solution. Kihm argues that distribution utilities will continue to play an important role in DER markets, including the ownership and management of DER assets, but acknowledges that regulators might have pause about allowing them to compete with third-parties in competitive DER markets. He lays out a future where DER markets did not "blossom fully of their own accord," and where some utilities had an opportunity to pursue cost-effective DERs on their own, while others sought partnerships to provide integration services to third-party DER providers.

Corneli hypothesizes a future that is defined by competition for DER products and services, primarily among third-parties, and where the utility role is primarily one of coordination. The primary services that the distribution utility (as distinct from the bulk power grid) provides in 2030 is "connected capacity" and "delivered energy." Connected capacity can be thought as the maximum amount of power that a user can draw from the distribution grid, while the energy is the volumetric kWh that can be used by the customer, up to the connected capacity limit. Despite the prevalence and low cost of DERs, it might still be economical for a customer to maintain some degree of connected capacity and occasionally purchase energy through the distribution grid. But, in this hypothetical future, the continue revenue erosion from DERs forced utilities to maintain profitability by focusing their investments in areas that provided value to customers. Coupled with the development of simple markets to allow customers to transact for DER services, utilities play a coordinating role in managing their grid.

Both authors agree that high penetrations of DERs will create changes in today's utility business model and will force regulators to define what areas they want to enable utilities to participate. This debate is currently playing out in the NY REV proceeding, where a focus on competitive markets has led NYPUC to preclude utilities from owning DERs in most circumstances and to act as the coordinator.

Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight

De Martini, P., and L. Kristov. 2015. *Future Electric Utility Series*. Lawrence Berkeley National Lab. Rep. no. 2

The second in the six-part Lawrence Berkeley National Lab "Future Electric Utility Series", this report from Paul De Martini and Lorenzo Kristov continues the discussion of the impact of DERs on the traditional monopoly structure of utility companies. Taking a continued deployment of DER as a given, the authors discuss how utilities and regulators can work to transition from the current paradigm to a sustainable utility business model in the future.

De Martini and Kristov define the transmission / distribution (T-D) interface as the logical junction to analyze the operational functions of the power grid of the future. They focus on the distribution grid operations, and leave aside retail supply functions. In this manner, they define three stages of distribution system evolution:

1. **Grid Modernization** – low levels of DER adoption that can be adapted to by existing system and planning procedures with minimum operational or procedural changes.
2. **DER Integration** – multi-way power flows begin to require new operational capabilities and increases the variability of the distribution grid. At the same time, DER penetration has reached a level where they can begin to provide real-time system benefits.
3. **Distributed Markets** – the arrival of "peer-to-peer" transactions between DERs and customers. This stage will require new regulatory frameworks and new market structures.

The authors detail the potential challenges and benefits that DERs can provide at each stage of the distribution grid evolution, and continue to discuss how regulators should consider structuring the utility to manage their integration. They arrive at three potential distribution system operator (DSO) models, each of which are discussed in turn.

- **The "Total ISO" model.** Here, the transmission-level ISO has full visibility into the distribution system and manages and optimizes the whole system. The authors find it intellectually interesting, but impractical to implement.
- **The "Minimal DSO" model.** The transmission-level ISO continues to optimize the whole system, but only models DERs at the T-D interface level. The DSO plays a significant coordinating role in managing and dispatching DERs on the distribution system.
- **The "Market DSO" model.** The most active role for the DSO where it either coordinates DER aggregators or acts as the DER aggregator to present the ISO one virtual DER resource at each T-D interface. DSOs are responsible for managing load and DER variability within each local network and coordinate dispatching at the T-D interface

While the second two examples are both seen as potential models for future distribution utilities, the authors discuss the various tradeoffs between the two models. Physical constraints must always be followed, and operational reliability may be increased by overbuilding DERs, but at added cost. They conclude their paper by walking through a process for stakeholders to analyze and define their policy aims, design the tools needed to account for and monetize DER value, and set up the organizational structures that are required to attain their policy objectives.

Performance-Based Regulation in a High Distributed Energy Resources Future

Lowry, M.N., and T. Woolf. 2016. *Future Electric Utility Series.* Lawrence Berkeley National Lab. Rep. no. 3.

Mark Lowry and Tim Woolf penned the third part of the six-part Lawrence Berkeley National Lab "Future Electric Utility Series." Building on the previous two reports in the series that laid the groundwork on the evolving challenges that utilities face in a high DER world, the authors explored performance-based regulation (PBR) and how it might be suited to meet these challenges.

Lowry and Woolf begin by discussing the incentive problems that exist in traditional cost of service regulation. These include incentives that vary based on when and how often rate cases are filed, incentives to increase a utility's rate base and energy sales, and a disincentive to accommodate DERs. Additionally, as DER penetrations increase, the risk of revenue erosion can hurt utility finances at the exact time when a robust grid is needed to integrate additional DERs.

PBR can help solve some of these misaligned incentives. Two common structures are discussed: multi-year rate plans (MRPs) and performance incentive mechanisms (PIMs). By granting a long-term rate case (and precluding utilities from coming in for adjustments during the duration of the MRP) that is tied to specific metrics and often accompanies by an automatic cost inflation adjustment mechanism, MRPs aim to provide an incentive for a utility to reduce its costs and increase its efficiency. Common components of MRP include revenue decoupling, shared savings structures, and cost trackers for capital investments.

PIMs help provide guidance to utilities by setting out specific performance goals and financial incentives to meet the targeted performance. To implement PIMs, regulators must be clear and specific in the types and structure of the goals they wish utilities to pursue. These metrics can be implemented in stages, starting with "scorecard" measurements before graduating to monetized performance, or beginning with incentives before moving to bi-directional incentives and penalties. PIMs are often used in conjunction with MRPs to ensure that the utility does not try to cut costs to the point that degrades service quality.

Britain's RIIO (Revenues = Incentives + Innovation + Outcomes) is one of the highest profile MRPs currently in place. In this process, electric and gas utilities operate under an eight-year plan with revenue decoupling, an inflation-adjustment mechanism, and incentives tied to customer service and reliability that directly impact utility earnings. RIIO also enables utilities to earn returns on total expenditures – as opposed to the more traditional return on capital expenditures – to remove incentives to only invest in projects that increase the rate base.

MRPs and PIMs have advantages and disadvantages from both the customer and utility perspective. For example, while MRP provide an incentive for utilities to reduce costs and share savings with customers, they also tend to lead to automatic rate increases. PIMs can help direct investment to areas where policymakers want focus, but they may entail high administrative costs and be subject to gaming and manipulation. Regardless of these challenges, PBR in a high DER world can be a useful tool in the regulator's toolbox.

Pathway to a 21st Century Electric Utility
Kind, P.H. 2015. Ceres.

Peter Kind was the author of EEI's 2013 report *Disruptive Challenges* that kicked off much of the current activity around the concept fixed cost recovery. While the intervening years saw considerable action – both by utilities and by DER advocates – related to increasing fixed charges, Kind released his late-2015 follow up report against a very different backdrop. Kind acknowledges that the push towards higher fixed costs over the past several years damaged the relationship between utilities and their customers, and in this report advocates a return to a more customer-value focus in utility ratemaking and operations.

Kind sees the distribution utility as the central integrator of resources and stakeholder collaboration to attain policy goals as expressed by consumers and policy makers. These policy goals include enhancing reliability and resiliency while maintaining affordability; recognizing the increasing importance of creating cleaner energy supply; optimizing system energy loads and load factors to reduce total cost to serve; and focusing on customer value, including the offering of service choice and easing adoption of DERs.

To attain these goals, Kind lays out four required foundational principles:

- The financial viability of utilities must be secured to enable them to fund and support enhanced capabilities on the grid
- Policymakers must define and promote clear policy goals in a comprehensive, integrated manner
- A commitment to engaging and empowering customers is necessary, including access to third party providers and necessary data
- Equitable tariff structures that promote fairness and policy goals must be implemented

Financial viability will be particularly crucial, as estimates suggest that electric utilities will need to spend between $75 and $100 billion annually to maintain current reliability levels. This is substantially higher than the $30 billion it generates in operating income, making continued reliance on market debt a must. Kind also argues that policy makers must clearly define the rules of the road, so that utilities can react to and plan towards them. These policy objectives should be constructed in a comprehensive manner and be consistent with jurisdictional divisions that exist. Customers are increasingly desiring choice in their energy supply, whether from clean generation or DERs. Kind suggests the current utility investment bias towards capital infrastructure needs to be shifted to focus on customer value. Finally, he argues that all of this requires that equitable tariff structures be in place to fairly record costs from those who use the distribution grid.

These principles are satisfied through actions that policy makers implement. Legislation such as EERS and RPS can send a clear signal as to what is important to states. Regulatory reform, including multi-year integrated planning at the transmission and distribution level, can anticipate and direct DERs to their optimal size and location. Tariff structures based on inclining block rates and bidirectional metering of DER customers help allocate costs, and active DR and TOU rates create incentives to manage the overall size of the grid.

All of these actions can be managed by developing an accountability and incentive framework that rewards utilities for creating customer value in addition to shareholder value. Performance-based ratemaking can include metrics on reliability, customer service, efficiency, and carbon intensity, while multi-year, forward looking rate cases provide utilities and their investors confidence to deploy capital.

Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future

Electricity Innovation Lab. 2014. Rocky Mountain Institute

RMI's report *Rate Design for the Distribution Edge* focuses on pricing characteristics that will become increasingly important in a high DER penetration world. While traditional rate structures that recovered costs through flat variable rates might have worked well in a past with high load growth and no customer-sited alternatives, they are unlikely to lead to optimal outcomes in a future where DERs increase in prevalence.

RMI calls for rates to become more sophisticated in response to the current challenges. Specifically, they suggest three areas in which rates can become more response: attribute unbundling (energy, capacity, ancillary services), temporal granularity (from flat/block to TOU/dynamic pricing), and locational granularity (treating all DER the same vs geotargeted pricing).

These three attributes are discussed in both near-term and longer-term scenarios:

Rate Characteristic	Near-Term Default or Opt-In Possibilities	Longer-Term, More Sophisticated Possibilities
Attribute Unbundling	Demand charges	Attribute-based pricing
Temporal Granularity	TOU w CPP Pricing	Real Time Pricing
Locational Granularity	Distribution "Hot Spot" Credits	Distribution Locational Marginal Price

Some of the longer-term possibilities require additional metering and systems capability, but as AMI deployments continue, these rate structures are poised to leverage that investment into delivering customer value.

RMI caution regulators to closely manage the complexity of the offerings to mass-market (i.e. residential and small commercial) customers, as rates must offer price signals that are not only economically efficient, but to which customers are able to understand and reasonably respond. Regulators must identify the timeline for a transition, and determine how to manage "opt-in" vs. "opt-out" considerations. They must also work to improve the overall rate design process, increasing transparency and accessibility to more stakeholders. Importantly, as DER penetration increases, rate design must anticipate changes to the net load profiles of the system to ensure that peak periods respond to the shifting loads and generation profiles of customers. Locking in a rate structure based on today's peaks may not be useful if the peak shifts after a significant deployment of DER.

Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs

Lazar, J. 2014. The Regulatory Assistance Project.

In this report, Jim Lazar focuses on the distinction between customer-specific charges and system charges. He suggests that true customer-specific marginal costs, such as billing and collection, are appropriately recovered through a fixed system charge that is independent of a customer's usage. But Lazar notes that utilities have been proposing fixed charges that include other systems elements, such as poles, transformers, and wires. In his view, collecting these system charges through a fixed customer charge is not consistent with economic principles, as rates should reflect the long-run marginal cost of a system, and all distribution plant is marginal in the long run.

A shift to higher fixed charges would have negative effects on low-use customers such as renters, low income households, and urban residents who rely on gas heating. Lazar also points out that higher fixed charges will result in lower variable costs, which in turn reduce the incentive for customers to conserve energy.

One potential alternative to raising fixed charges is to adopt a minimum bill. In this structure, a small customer charge will still be collected, but the majority of a customer's costs will remain in an economically efficient variable rate. For very low-use customers or customers with DG offsetting most or all of their load, a minimum bill will ensure that they contribute some degree to the recovery of system costs. Lazar calculates that the difference between a $20 minimum bill and a $20 fixed charge would result in about 15 times as much additional usage in the fixed charge option.

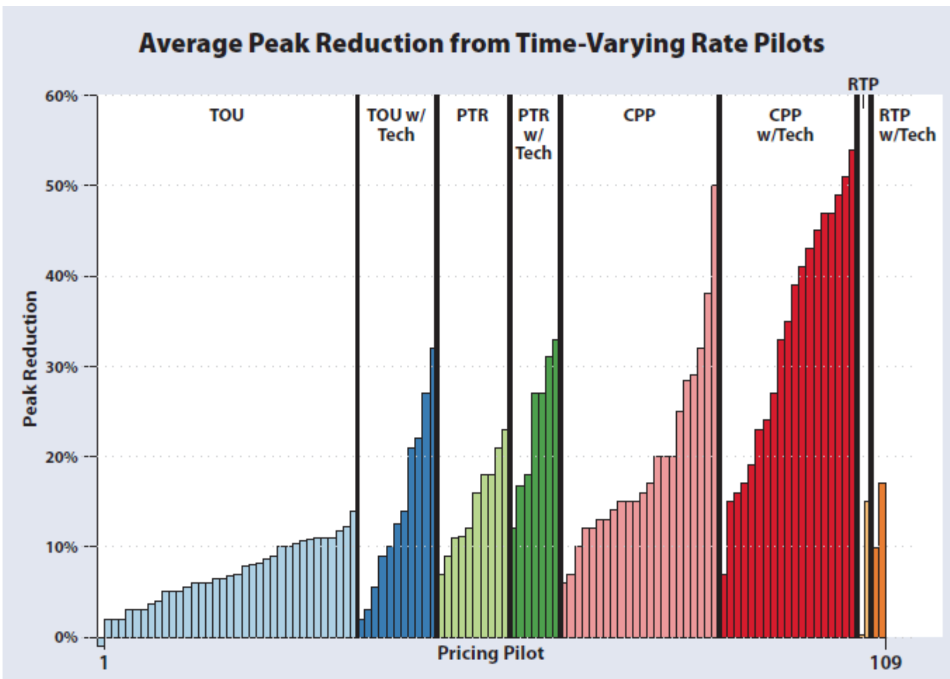
Lazar also notes that high fixed charges are often discussed in the context of distributed PV customers. For a customer that offsets most of all of their load through net metering, it is currently possible that they do not contribute any funds towards the recovery of system costs. A minimum bill would ensure that they contribute towards these costs, but would not distort rate signals for all customers in the process as a high fixed charge would.

Time-Varying and Dynamic Rate Design

Faruqui, A., R. Hledik, J. Palmer. 2012. *Global Power Best Practice Series.* Regulatory Assistance Project and the Brattle Group

Advances in metering technology are opening up new avenues in rate design that did not exist with legacy meters. Rate designs that vary based on time or system conditions are better as sending efficient price signals to customers. By altering energy prices based on known or anticipated times of peak load, customers will have incentives to reduce their own use, thus reducing the total load on the system, and subsequently reducing the costs of serving all customers. Additionally, with the increased variability of supply from non-dispatchable resources, dynamic pricing can help load respond to supply in a more efficient manner.

While TOU rates have been around for decades, their overall participation levels have tended to be low. Nonetheless, results from pilot programs have demonstrated that these rate structures help reduce system peaks, in some cases substantially so, as seen in the diagram below. However, there is not a strong conservation effect from historic TOU rates, as customers tend to simply shift their energy use rather than reduce it. The authors note that this is an area where additional research will be useful.



When implementing time-varying rates, the authors recommend a seven-step process:

0. **Understand the impacts of current rates.** Utilize focus groups and surveys.
1. **Develop a consistent and comprehensive set of ratemaking objectives.** This should be done in advance of ratemaking design to ensure outcomes are desired.
2. **Identify the menu of possible new rate options.** What options are on the table? Is AMI available?
3. **Perform preliminary assessment of potential impacts.** Develop rate designs from real data.
4. **Conduct preliminary market research.** Investigate customer response to initial designs.
5. **Conduct time-varying rate pilots.** Include shadow bills and monitor impact on low income customers.
6. **Full-scale deployment of innovative rates.** Identify rates that best align with policy objectives and more to roll out more broadly

Appendix A – ACEEE Ranking and Quintile

ACEEE Scorecard Ranking								
State	2011	2012	2013	2014	2015	Average	Rank	ACEEE Quintile
Massachusetts	1	1	1	1	1	1	1	1st
California	2	2	2	2	2	2	2	1st
Oregon	4	4	4	3	4	3.8	3	1st
Vermont	5	5	7	3	3	4.6	4	1st
Rhode Island	5	7	6	3	4	5	5	1st
New York	3	3	3	7	9	5	6	1st
Connecticut	8	6	5	6	6	6.2	7	1st
Washington	5	8	8	8	8	7.4	8	1st
Maryland	10	9	9	9	7	8.8	9	1st
Minnesota	8	9	11	10	10	9.6	10	1st
Iowa	11	11	12	14	12	12	11	2nd
Illinois	17	14	10	11	10	12.4	12	2nd
Colorado	12	14	16	13	12	13.4	13	2nd
Michigan	17	12	12	12	14	13.4	14	2nd
Arizona	17	12	12	15	17	14.6	15	2nd
Maine	12	25	16	16	14	16.6	16	2nd
New Jersey	15	16	12	19	21	16.6	17	2nd
Hawaii	12	18	20	17	19	17.2	18	2nd
Wisconsin	16	17	23	17	22	19	19	2nd
Pennsylvania	25	20	19	20	17	20.2	20	2nd
New Hampshire	21	18	21	22	20	20.4	21	3rd
Utah	17	21	24	23	23	21.6	22	3rd
District of Columbia	22	29	30	21	14	23.2	23	3rd
Ohio	24	22	18	25	27	23.2	24	3rd
North Carolina	27	22	24	24	24	24.2	25	3rd
Delaware	31	27	22	25	24	25.8	26	3rd
New Mexico	27	27	24	25	31	26.8	27	3rd
Florida	27	29	27	28	27	27.6	28	3rd
Idaho	26	22	31	30	29	27.6	29	3rd
Nevada	22	31	33	29	31	29.2	30	3rd
Montana	35	25	29	31	31	30.2	31	4th
Texas	33	33	33	34	26	31.8	32	4th
Tennessee	30	32	31	38	31	32.4	33	4th
Indiana	32	33	27	40	38	34	34	4th
Virginia	34	37	36	35	31	34.6	35	4th
Kentucky	37	36	39	33	29	34.8	36	4th
Arkansas	38	37	37	31	31	34.8	37	4th
Georgia	36	33	33	35	37	34.8	38	4th
Oklahoma	47	39	37	35	38	39.2	39	4th
Alabama	43	40	39	39	41	40.4	40	4th
South Carolina	46	40	39	42	40	41.4	41	5th
Nebraska	40	42	44	42	42	42	42	5th
Kansas	48	45	39	40	45	43.4	43	5th
Missouri	44	43	43	44	44	43.6	44	5th
Louisiana	40	43	44	44	48	43.8	45	5th
Alaska	38	46	47	47	42	44	46	5th
West Virginia	44	49	46	46	45	46	47	5th
South Dakota	42	46	47	49	48	46.4	48	5th
Mississippi	49	51	47	47	47	48.2	49	5th
Wyoming	50	48	50	50	50	49.6	50	5th
North Dakota	51	50	51	51	51	50.8	51	5th

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