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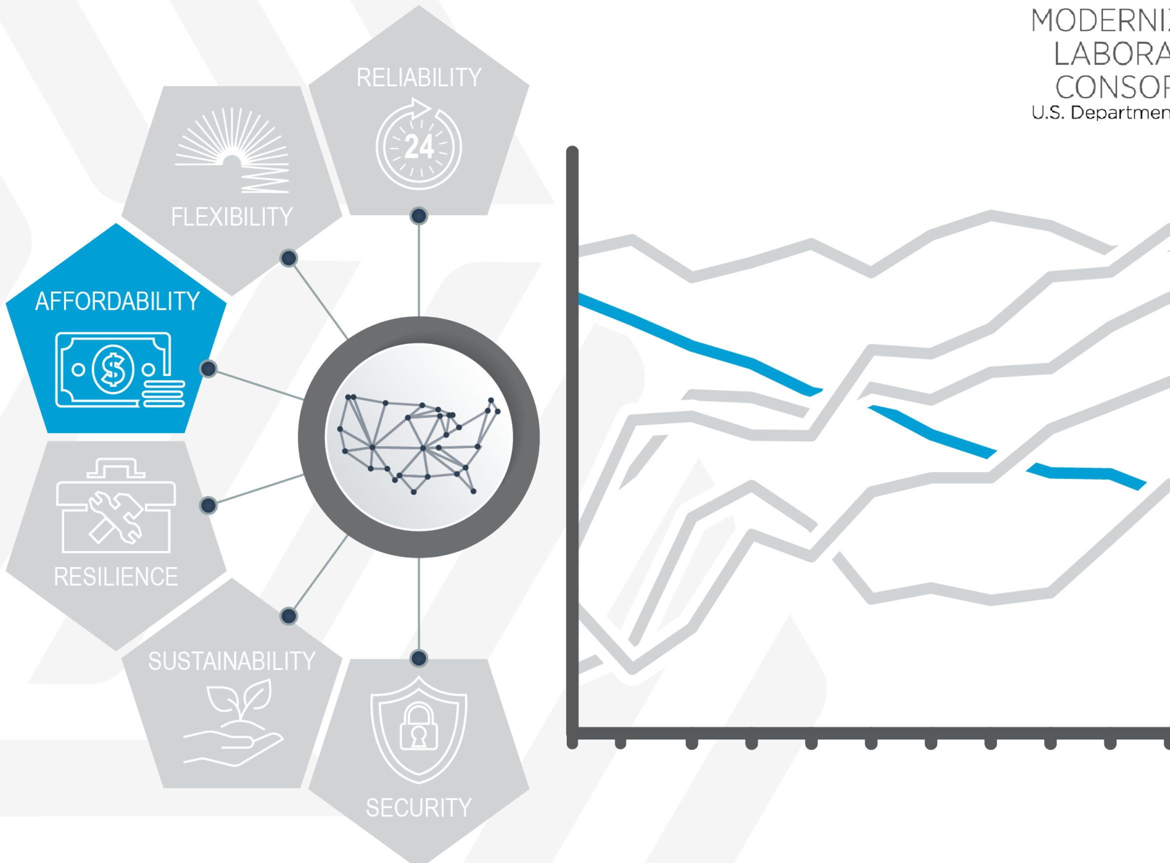

Grid Modernization: Metrics Analysis (GMLC1.1) – Affordability

Reference Document
Volume 6

April 2020

Grid Modernization Laboratory Consortium

PNNL-28562

PACIFIC NORTHWEST NATIONAL LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC05-76RL01830

Printed in the United States of America

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April 2020

Prepared for
the U.S. Department of Energy
under Contract DE-AC05-76RL01830

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Summary

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Affordability
The ability to provide electric services at a cost that does not exceed customers' willingness or ability to pay for these services.

The GMLC Metric Team: 1) Identified important, but often overlooked, affordability metrics that measure the impacts of electricity costs on residential customers (customer cost burden, affordability gap, and affordability headcount gap); 2) Created a public-facing website for the residential sector that compiles publicly available data and displays affordability metrics at both the state and county level; and 3) demonstrated the use of the metrics and website for three remote village utilities in Alaska and a major electricity utility in California, Southern California Edison (SCE).

S.1. Motivation

Cost-effectiveness is the most well-known perspective, from which the affordability of grid modernization activities is assessed. However, cost-effectiveness does not address an important, related, yet often incompletely considered aspect of affordability: namely, the cost burdens on customers that result from utility recovery of the costs of grid modernization activities through electricity bills. The cost burden connotation recognizes the notion that while grid technology investments may prove to be cost-effective, they also necessarily lead to obligations for customers to pay for them; these obligations may or may not be affordable (i.e., they may exceed the customer's willingness or ability to pay).

Cost-burden is typically expressed as the proportion of income or revenue required to acquire a desired level of electricity service. They are the costs to customers that result from application of the utility's retail tariffs to the amount of electricity that a customer consumes. Customer cost burden can be compared to some expected normal or expected burden for a specific geographic area of interest (service territory, state, balancing area, interconnect, etc.).

Customer cost-burden metrics are gaining in importance to individual utilities from the social responsibility perspective. Affordability metrics derived from customer cost burden may become a differentiator for utility service providers, in the context of socially responsible electricity delivery.

S.2. Outcomes/Impact

The GMLC team focused initially on the residential sector. The team identified and then based its work on six affordability metrics:

- Household electricity burden
- Household electricity affordability gap
- Household electricity affordability gap index
- Household electricity affordability headcount index
- Annual average customer cost
- Average customer cost index
- Commercial electricity marginal revenue product

- Industrial marginal revenue product.

The team developed a geographic dashboard tool to display the metrics spatially as shown in Figure S.1. The tool displays each metric for all 50 states in one view and all counties within the states in another view. From this global view, the user can drill down to increasing levels of granularity.

Affordability headcount gap is a principal metric that is displayed on the dashboard. The affordability headcount gap is a measure of the percentage of households within a state or county that faces monthly electricity costs that exceed a threshold percentage of their monthly income. Expressed in this fashion, it is a measure of the percent of households for whom electricity is not affordable.

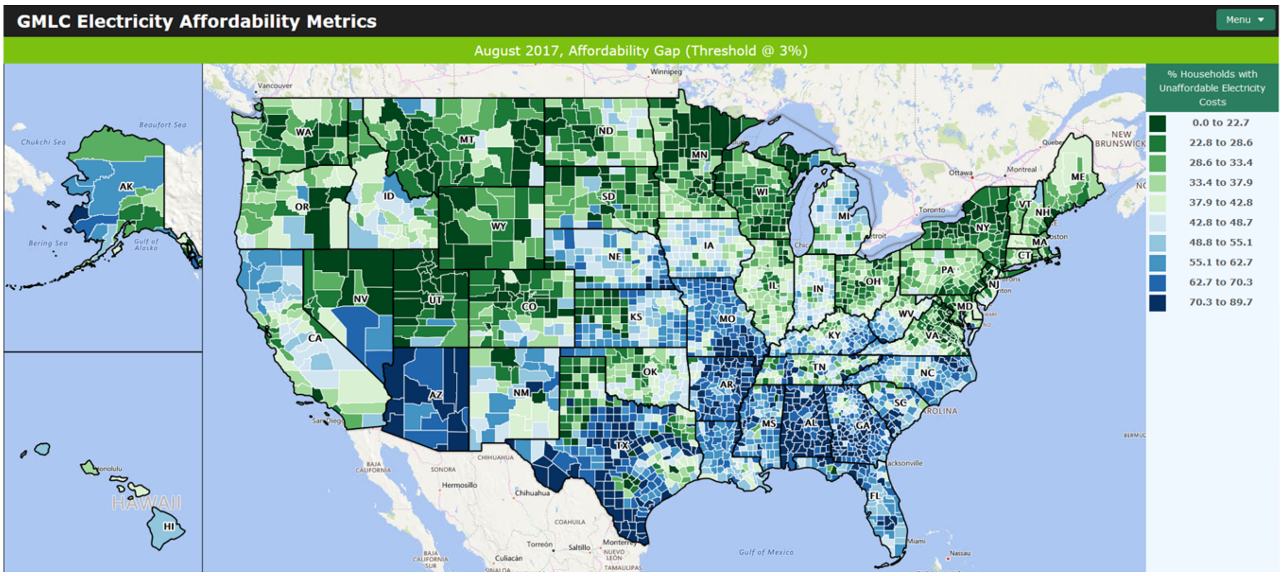

Figure S.1. County View of the Affordability Dashboard Tool

The team conducted two case studies with industry partners to demonstrate the usefulness of the tool and affordability metrics it displays.

The first case study was conducted in partnership with the Alaska Microgrid Project (AMP), a sister GMLC project. The AMP designed renewable-based microgrids for three remote Alaskan villages, Chefornak, Kokhanok, and Shungnak, as a means of mitigating the extreme costs associated with transporting petroleum-based fuel to their remote locations for power generation. There is clear linkage with the affordability metric, because the reason for the AMP is to demonstrate that renewable resource solutions can reduce fuel costs, and therefore customer costs, to villagers throughout Alaska.

The team found that, based on increasing average cost burdens, electricity affordability has declined through 2015 for Chefornak because electricity costs have increased faster than incomes. The team found that electricity has become slightly more affordable for Kokhanok because of a slight drop in electricity costs, paired with stable incomes. Finally, the team found that electricity affordability has improved for Shungnak because average electricity costs have declined slightly, while incomes have remained relatively stable.

The second case study was conducted in partnership with Southern California Edison. This case study compared baseline metrics derived from public data sources to the same metrics derived from the utility's proprietary customer billing data. The interest to both parties is to identify and test whether the residential sector metrics developed in this volume using public data sources would produce similar metric values to estimates derived using the unpublished, utility-supplied data.

Results were developed at the utility level, the county level, and the census tract level for several metrics for the years 2015, 2016, and 2017. Using the published data from EIA's Form-861, relatively good agreement resulted when comparing to SCE's unpublished data for utility level metrics such as the number of customers and the usage of electricity. Results analyzed at the county level also indicate that the public data does a reasonable job in comparison to the unpublished data for estimating customer average cost burdens for the core counties of the SCE service area (Los Angeles, Ventura, San Bernardino, Riverside, Orange) and are less effective for the edges of the service area where SCE may not dominate the market. Census tract level results were not as encouraging when estimating example metrics other than simply comparing the number of customers and electricity sales.

The GMLC effort also has resulted in the development of entirely new metrics addressing electricity affordability in the commercial and industrial sectors. Unlike residential electricity customer affordability, electricity affordability affects the profit function of a business. Commercial and industrial customers use electricity as an input to the production of goods and services. This volume offers a novel approach to analyzing electricity affordability for businesses.

Electricity costs affect business profitability. If a business is operating profitably, then electricity costs are found to be affordable. If increased electricity costs would flip a business from reaping profits to incurring losses, electricity costs are found to be unaffordable, without additional adjustments in the production function of the business to offset the effects of the electricity costs. Thus, metrics have been developed to attribute the effect of electricity costs on profits. The marginal revenue product of electricity measures the benefits (or losses) attributable to acquiring more electricity in the operation of the firm and, in aggregate, entire industries.

Examples of the marginal revenue product of electricity have been developed for the automotive industry (industrial customers) and the food services industry (commercial customers). State-level results for these industries and plant- or firm-level results within states are presented as examples of the metrics. In nearly all cases, electricity is within the affordable threshold using this metric.

Acknowledgements

The authors would like to acknowledge the cooperation of the two entities that contributed unpublished data to our affordability use cases. These include Southern California Edison and the Alaska Energy Authority. Lending summarized and anonymized electricity billing data to this effort was essential to testing the metric estimations. We also acknowledge those groups who played a role in helping steer and review this effort periodically during the project. These groups include EPRI, Washington Utility and Trade Commission, Colorado State Energy Office, Minnesota Public Utility Commission, and Clean Energy States Alliance.

Acronyms and Abbreviations

ACE	area control error
ACEEE	American Council for an Energy Efficient Economy
ACS	American Community Survey
AMP	Alaska Microgrid Project
BCA	benefit-cost analysis
BEA	Bureau of Economic Analysis
ConEd	Commonwealth Edison
CPUC	California Public Utilities Commission
CT	combustion turbine
DER	Distributed Energy Resource
DOE	U.S. Department of Energy
DSM	demand-side management
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
EV	electric vehicle
EPRI	Electric Power Research Institute
FRED	Federal Reserve Economic Data
GMLC	Grid Modernization Laboratory Consortium
GMLC1.1	Grid Modernization Laboratory Consortium Project Metrics Analysis
IMPLAN	Economic Impact Analysis for Planning
IRP	Integrated Resource Plan
IRR	internal rate of return
kWh	kilowatt hour
LCOE	Levelized Cost of Electricity
MIRR	modified internal rate of return
MWh	megawatt hour
MYPP	Multi-Year Program Plan
NEI	non-energy impact
NEM	net energy metering
NERC	North American Electric Reliability Corporation
NESP	National Efficiency Screening Project
NIPA	National Income and Product Accounts
NPV	net present value
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission

O&M	operation and maintenance
PAC	Program Administrator Cost
PCE	Power Cost Equalization (program); or
PUC	Public Utilities Commission
PV	photovoltaics
PVRR	present value of revenue requirements
REC	renewable energy credits
RECS	Residential Energy Consumption Survey
RIM	Ratepayer Impact Measure
RPS	renewable portfolio standard
RTO	regional transmission organization
RVT	Resource Value Test
SCT	Societal Cost Test
SPB	simple payback period
TRC	Total Resource Cost
UCT	Utility Cost Test
VOS	Value of Solar

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1.0 Introduction

1.1 Project Background and Motivation

The U.S. Department of Energy's (DOE's) 2015 Grid Modernization Initiative Multi-Year Program Plan (MYPP) states that as the US electric grid transitions to a modernized electric infrastructure, policy makers, regulators, grid planners, and operators must seek balance among six overarching attributes (DOE 2015a): (1) reliability, (2) resilience, (3) flexibility, (4) sustainability, (5) affordability, and (6) security. Some attributes have matured and are already clearly defined with a set of metrics (e.g., reliability), while others are emerging and less sharply defined (e.g., resilience). To provide more clarity to the definition and use of the attributes, DOE is funding an effort that will evaluate the current set of metrics, develop new metrics where appropriate, or enhance existing metrics to provide a richer set of descriptors of how the US electric infrastructure evolves over time.

DOE engaged nine national laboratories to develop and test a set of enhanced and new metrics and associated methodologies through the Grid Modernization Laboratory Consortium (GMLC) Metrics Analysis project, generally referred to by its acronym GMLC1.1.

The project supports the mission of three DOE Offices—Office of Electricity Delivery and Energy Reliability, Office of Energy Efficiency and Renewable Energy, and Office of Energy Policy and Systems Analysis—by revealing and quantifying the current state and the evolution over time of the nation's electric infrastructure.

This project started in April 2016 and ended in March 2019.

1.2 Metric Categories Definitions

The MYPP uses the term attribute to describe the characteristics of the power grid. In this report, we use the term "metric areas" or metric categories. Metrics are physical or economic considerations that can be measured or counted. Several metrics can be grouped into a metric category.

The six metric categories explored in this project are described in Table 1.1. The purpose of this table is to list commonly used definitions and indicate which aspects of the large breadth within a metric category this project addresses.

Table 1.1. Metrics Descriptions and Focus Areas

Metric Categories	Definitions	Focus Areas under GMLC 1.1
Reliability	Maintain the delivery of electric services to customers in the face of routine uncertainty in operating conditions. For utility distribution systems, measuring reliability focuses on interruption of the delivery of electricity in sufficient quantities and of sufficient quality to meet electricity users' needs for (or applications of) electricity. For the bulk power system, measuring reliability focuses separately on both the operational (current or near-term	We are developing new metrics of distribution reliability, which account for the economic cost of power interruptions to customers, with the American Public Power Agency. Developing new metrics of bulk power system reliability for use in the North American Electricity Reliability Corporation's Annual State of Reliability Report.

Metric Categories	Definitions	Focus Areas under GMLC 1.1
	conditions) and planning (longer term) time horizons.	We are demonstrating the use of probabilistic transmission planning metrics with the Electric Reliability Council of Texas, Inc. and Idaho Power.
Resiliency	Can prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions, including the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents (Obama 2013).	We apply a consequence-based approach that defines a process using resilience goals to a set of defined hazards. This approach provides the information needed to prioritize investments for resilience improvements.
Flexibility	Respond to future uncertainties that may stress the system in the short term and require the system to adapt over the long term. Short-term flexibility to address operational and economic uncertainties that are likely to stress the system or affect costs. Long-term flexibility to adapt to economic variabilities and technological uncertainties that may alter the system.	We focus on flexibility of the bulk power system needed to accommodate variability of net load, which is the load minus variable generation including high penetrations of variable resource renewables.
Sustainability	Provide electric services to customers, minimizing negative impacts on humans and the natural environment.	We focus on environmental sustainability, specifically in Year 1, assessing metrics for greenhouse gas emissions from electricity generation. In Years 2 and 3, we also explore water metrics.
Affordability	Provide electric services at a cost that does not exceed customer willingness and ability to pay for those services (Taft and Becker-Dippman 2014).	We document established investment cost-effectiveness metrics and focus our research on emerging customer cost-burden metrics.
Security	Prevent external threats and malicious attacks from occurring and affecting system operation. Maintain and operate the system with limited reliance on supplies (primarily raw materials) from potentially unstable or hostile countries. Reduce the risk to critical infrastructure by physical means or defense cyber measures to intrusions, attacks, or the effects of natural or man-made disasters (Obama 2013).	We develop metrics to help utilities evaluate their physical security posture and inform decision-making and investment.

2.0 Approach

The GMLC 1.1 Foundational Metrics approach to affordability has been to focus on the development of metrics that address electricity affordability from the customer cost-burden side of the question. For completeness, this volume provides extensive documentation of existing cost-effectiveness metrics. However, the bulk of the effort has been to identify and provide use-case examples of metrics that derive from the cost burden facing the customer. This has been demonstrated for the residential customer class and a methodology has been developed for the commercial and industrial customer classes.

The foundational basis for modern grid architecture specification defines affordability as a system quality that "ensures system costs and needs are balanced with the ability of users to pay" (Taft and Becker-Dippmann 2014). Depending on the stakeholder's objectives, electricity affordability is defined either as the quantification of the cost effectiveness of grid investments or the quantification of the burden on customers of the net costs associated with receiving electric service.

Established metrics for cost-effectiveness are acknowledged and documented, but most recent metric development effort has been devoted to defining metrics designed to inform stakeholders and decision-makers about the customer cost burden imposed by the technology investments to achieve grid modernization. The cost-burden connotation recognizes the notion that while grid technology investments may prove to be cost-effective for their investors, the resulting cost burden on customers may or may not be affordable (i.e., costs might exceed the customer's willingness or ability to pay). If the cost burden on customers is above the affordable threshold for their income, or "unaffordable," it simply implies that these customers are likely foregoing other elective expenditures, rather than losing their electric service. Unaffordable electricity does not imply that customers are foregoing their electric service for lack of ability to pay.

3.0 Stakeholders and Partners

A critical aspect of this project is to ensure that the metrics being developed directly benefit the electricity sector. Throughout the process of developing and testing the metrics from this project, input and feedback have been sought from stakeholders.

Key national organizations in the electricity industry were identified as Working Partners at the inception of the project and engaged to provide both strategic and technical input to the project. Three types of organizations were also identified for each of the six individual metric areas: (1) primary metric users, (2) subject matter experts, and (3) data or survey organizations. These stakeholders were engaged at various stages of the project, especially at the beginning and scoping stages of the effort, and then to more formally review the content in this document at the end of Year 1.

The project team engaged with, received feedback from, and in some cases, formed a partnership with the following entities, related to affordability:

- Alaska Energy Authority
- Colorado State Energy Office
- Electric Power Research Institute
- Minnesota Public Utilities Commission
- National Association of Regulatory Utility Commissioners
- Southern California Edison
- Washington State Utilities and Transportation Commission.

3.1 Users of this Research

Three groups will directly benefit from adopting the approaches defined by the GMLC efforts related to affordability metrics. First, public utility commissions (PUCs), or their equivalent organizations, would benefit from understanding baseline affordability conditions in their state or equivalent jurisdiction. Understanding the state of electricity affordability is necessary before examining the impacts of specific commission decisions affecting rates. Second, utilities have a vested interest in being knowledgeable about the baseline affordability conditions in their service territories. If utility commissions take active interest in questions regarding electricity customer affordability, then utilities need to be armed with metrics for their service areas in order to provide quantitative information in docket proceedings. Finally, as a natural offshoot of developing metrics addressing affordability, consumer advocates have an interest such metrics. These metrics can be used by advocacy groups to support positions that address improving the affordability of electric service for disadvantaged groups. The tools and approaches have been discussed with a few stakeholders and presentation venues thus far, and additional publications are in development.

4.0 Affordability Outcomes

Electricity affordability is approached from two perspectives: cost effectiveness and cost burden. Most established metrics have been developed to determine cost effectiveness or to answer the question “will a specific investment pay off subject to return on investment criteria?” Emerging metrics determine the electricity service cost burden affecting end-use customers by answering the question “what portion of customers’ income or revenue is required to pay for electricity service?”

Electricity affordability implies different things to different stakeholders:

- Residential customer: proportion of electricity costs to household income (cost burden)
- Commercial/industrial customer: proportion of electricity costs to gross revenue (cost burden)
- PUC: the economic effect of provision of electricity on rate payers, underserved markets, and other stakeholders
- Utility: the most prudent (economically efficient) resource investments given the constraints
- Merchant: economic efficiency, maximizing returns to owner.

4.1 Definition

The foundational basis for modern grid architecture specification defines affordability as a system quality that “ensures system costs and needs are balanced with the ability of users to pay” (Taft and Becker-Dippmann 2014). Depending on the stakeholder’s objectives, electricity affordability is defined either as the quantification of the cost effectiveness of grid investments or the quantification of the burden on customers of the net costs associated with receiving electric service.

Established metrics for cost effectiveness are acknowledged and documented, but most recent metric development effort has been devoted to defining metrics designed to inform stakeholders and decision-makers about the customer cost burden imposed by the technology investments to achieve grid modernization. The cost-burden connotation recognizes the notion that while grid technology investments may prove to be cost effective for their investors, the resulting cost burden on customers may or may not be affordable (i.e., costs might exceed the customer’s willingness or ability to pay).

4.2 Established Metrics

Several mature metrics address the *cost effectiveness* or *cost competitiveness* of different resource options. The cost effectiveness/competitiveness metrics are used to examine affordability from the standpoint of making investments in new technologies, services, practices, or regulations. This set of metrics includes two general categories of metrics, one that has typically been associated with generating or “supply-side” resources, and another that has typically been associated with customer- or demand-side resources.

Within the first general category of metrics are Levelized Cost of Energy (LCOE), Internal Rate of Return, Net Revenue Requirement, Simple Payback Period, and Avoided Cost. The second general category includes a series of Benefit-Cost Analyses historically associated with subsets of Distributed Energy Resources (DERs). Note, however, that while the metrics tend to be associated with supply-side or demand-side resources, this does not mean they are exclusively used in that way. For example, the financial advisory and asset management firm, Lazard Ltd (Lazard), produces two reports based on the LCOE metric: one compares the LCOE for conventional and “alternative” generating technologies

(Lazard 2017), and the other compares the LCOE of storage technologies—typically considered a form of DER (Lazard 2016). Similarly, Benefit-Cost Analysis (BCA) metrics, typically linked to customer-side resources, can be used to generate levelized costs, revenue requirements, and payback periods. So, while the two general categories of metrics are linked to either supply- or customer-side resources, significant efforts have gone into making the metrics comparable or compatible.

Short et al. (1995) is an often-cited report documenting cost-effectiveness metrics in the energy domain. Another often-cited document is the California Public Utility Commission (CPUC) Standard Practice Manual (CPUC 2001). The most widely accepted metrics are presented in the following sections.

4.2.1 Levelized Cost of Electricity

4.2.1.1 Definition

The LCOE is the total cost of installing and operating a project expressed in dollars per kilowatt-hour of electricity generated by the system over its life. It translates the string of costs and production over time into a single value, which, if charged to each unit of production, would give the same net present value as the actual cost stream. Some analyses use nominal (inflated) dollars, while others use uninflated or real dollars in the calculation. The simple equation is as follows:

$$LCOE = \frac{NPV(Costs)}{NPV(Production)}$$

Costs can be as simple as construction and operating costs, or can be expanded to include taxes, financing costs, incentives, and salvage value. For generation such as wind or solar with no fuel costs, the LCOE changes in proportion to the capital cost estimates. For technologies with significant fuel costs, both the fuel cost and capital cost significantly affect the LCOE (EIA 2017).

Production is the total electricity generated in kilowatt-hours over the life of the asset. The NPV (or net present value) of cost is the sum of all costs over the life of the asset with future amounts discounted by a specified discount rate (d):

$$NPV = \sum_{i=0}^{N} Cost_i * (1 + d)^{-i}$$

4.2.1.2 Maturity Level

This measure has been well known and applied for decades if not longer.

4.2.1.3 Applications

The LCOE has been used for calculating the cost effectiveness of projects. By incorporating different categories of cash flows, different stakeholder interests can be examined.

4.2.1.4 Data Source and Availability

Publicly recognized data sources include Energy Information Administration (EIA) assumptions for its annually published Annual Energy Outlook (EIA 2013b; EIA 2017), the Lazard studies, and the data from the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (Sullivan et al. 2015). Individual projects will likely have their own more specific cost data. More detailed cost analysis requires local, state, and federal tax code and incentives information, and general accounting practices.

4.2.2 Internal Rate of Return

4.2.2.1 Definition

Internal rate of return (IRR) is defined as the discount rate that makes the NPV of the cost and revenue stream equal to zero. IRR is often used as a metric for making quick decisions to accept or reject an investment in a single project (Short et al. 1995).

IRR is calculated as the discount rate (*d*) that sets NPV equal to zero, or:

$$0 = NPV = \sum_{i=0}^{N} (Flows_i \div (1+d)^i)$$

where:

Flows = all cash flows, including

- upfront capital cost
- ongoing or periodic operations and maintenance (O&M) costs
- depreciation
- revenues
- income and other taxes
- other.

4.2.2.2 Maturity Level

This measure has been well known and applied for decades.

4.2.2.3 Applications

IRR has been used for calculating the cost-effectiveness of projects. By incorporating different categories of cash flows, different stakeholder interests can be examined. Investors would undertake projects where the IRR exceeded their hurdle rate, or the minimum acceptable rate of return.

As noted in the definition, IRR provides a quick accept/reject assessment of a single project. However, if using the IRR to compare alternative investments, the IRR has some shortcomings that make it desirable to use the IRR in conjunction with other metrics rather than using it as a stand-alone metric. The IRR calculation values cash flows at the same rate, but a more accurate calculation would value some cash flows at different rates. For example, a capital investment in some future year would be funded at the company's cost of capital rather than at the discount rate implicit in the IRR calculation. For this reason, the IRR is not recommended for projects involving large downstream capital costs. Similarly, the IRR implicitly assumes positive cash flows (net revenues) are invested at the discount rate calculated in the IRR formula, which can lead to an overstatement of the potential profitability. To counteract the issues related to inappropriately valuing future capital investments or future returns from the investment of positive cash flows, analysts can employ a modified IRR or MIRR to explicitly account for these factors

(Short et al. 1995). Finally, the timing of flows can lead to situations in which a decision based solely on IRR would lead to a less profitable project being selected than a decision based on an NPV analysis (Short et al. 1995).

4.2.2.4 Example

An example calculation of IRR is provided below. The example uses assumptions based upon the Consolidated Edison BCA Handbook (ConEd 2016) supplemented with a report prepared for the New York Energy Research and Development Authority and New York State Department of Public Service by Energy + Environmental Economics (E3 2015). The example assumes a consumer was considering investing in solar photovoltaics (PV) and their situation included the following values:

- Time period – 20 years, 2016 to 2035
- Installed cost (2015$/kW – alternating current [AC]) – $4,430
- Project size (AC) – 4 kW
- Assuming a 13.59% capacity factor3, the unit generates 1,190 kWh/kW-direct current (DC)
- Conversion factor, DC to AC – 95%
- Fixed operating cost (2015$/kW) – $15
- Tax credits – total of 55 percent, 30% federal and 25% state
- Assume the customer purchases with cash, so financing carrying costs are not an issue
- Base year net energy metering (NEM) credit (2015$/kWh) – $0.22
- General, overall inflation – 2%
- Incentives from utility other than NEM payments – none.

With these input assumptions, the solar PV installation would have an IRR of 14 percent. If the consumer's hurdle rate was set to any rate below 14 percent, then the solar PV installation would look like a good investment to them.

4.2.3 Simple Payback Period

4.2.3.1 Definition

The simple payback period (SPB) is defined as the length of time after the first investment that the undiscounted sum of costs and revenues equals zero. SPB is relatively easy to use because the first-year costs and benefits are relatively easy to identify.

SPB can be defined as follows:

$$SPB = (\Delta Capital\ Cost \leq \Delta Cash\ Flow)\ or, rearranging\ terms,$$

$$\text{SPB} = \frac{\Delta Capital\ Cost}{\Delta Cash\ Flow}$$

[3] Most of the later examples use more rounded inputs. This calculation used a capacity factor taken straight from the data set referenced in the text.

where:

ΔCapital Cost	=	the upfront capital cost net of any tax credits or other incentives
ΔCash Flow	=	net first-year benefits (revenues) less first-year operation and maintenance (O&M) cost increases.

4.2.3.2 Maturity Level

This measure has been well known and applied for decades.

4.2.3.3 Applications

SPB has been used for calculating the cost-effectiveness of projects. If the SPB is less than the expected useful life of the equipment, the investment is cost effective. SPB can be particularly valuable in situations of uncertainty when investors want to know how long their investment will be at risk. While simple to calculate, the SPB does not give as meaningful a result as the NPV or IRR, because it only tells how long it will take until the costs have been recovered, without providing an estimate of the total return. It does not capture any information about the time value of money, or the impact over the full life of the project.

4.2.3.4 Example

Using the assumptions from the IRR calculation for the hypothetical solar PV system (listed below), the unit would be a cost-effective investment for the consumer because the SPB is shorter than the assumed life of the unit.

- Installation costs $7,974 ($17,720 minus $9,746 tax credits)
- Net first-year revenues are $984 (revenues from NEM of $1,048 less first-year O&M of $63)
- SPB = $7,974/$984 or 8.1 year
- Life of the unit assumed to be 20 years.

4.2.4 Net Revenue Requirements

4.2.4.1 Definition

Net revenue requirements are defined as the annual stream of revenue necessary to recover the total costs of a project including capital (in the form of depreciation), operating costs including fuel, financing costs including interest and required return on rate on equity, and taxes including both costs and incentives. The net revenue requirements formula provided below is most applicable to regulated utilities that are allowed a regulated rate of return on an approved rate base of investment.[4] Net revenue requirements can be defined as follows:

$$RevReq = Fuel + O\&M + Depreciation + Taxes + Return\ on\ Rate\ Base + Other$$

[4] Consumer-owned utilities may or may not use a different set of cost accounts to capture costs related to equipment ownership. For example, instead of depreciation and return on rate base they may use an allowance for capital investment (to accrue money for pay-as-you-go investment) and debt service payments.

Because these factors will vary over time, the revenue requirements will change and inflation will increase some costs, while depreciation will reduce other costs. Accounting rules, tax incentives, accelerated depreciation, changes in allowed rate of return, life of debt, frequency of rate hearings, adjustment clauses, and other policy and rate-setting factors will all play a role.

For long-term applications the metric will be the present value of revenue requirements or PVRR. The formula for PVRR is as follows:

$$PVRR = \sum_{i=1}^{N} \frac{(Fuel_i + O\&M_i + Depreciation_i + Taxes_i + Return\ on\ Rate\ Base_i + Other)}{(1+d)^i}$$

The discount rate used is typically a utility's weighted cost of capital. The PVRR formula discounts the revenue requirements to Year 0. If a Year 1 value is desired the discount factor should be $(1+d)^{(i-1)}$.

4.2.4.2 Maturity Level

Regulated rates and consequent revenue requirement calculations have been in existence for over a century.

4.2.4.3 Applications

Revenue requirements are typically calculated and used on a company-wide basis, but the impacts of single projects on revenue requirements can be calculated by applying the rules to the subset of costs applicable to or affected by the project.

PVRR is widely used in integrated resource planning to compare future resource portfolios. The portfolios selected as the preferred portfolios are typically those exhibiting the lowest PVRR, subject to the portfolios meeting other constraints such as enabling the utility to meet renewable portfolio standards or risk criteria.

4.2.4.4 Example

In the following example a utility desires to compare a conventional combustion turbine (CT) to other resources using a revenue requirement analysis. For this example, the following assumptions are used:

- Capacity (MW): 85 (from EIA 2013b)
- Cost: $973/kW, or $82.7 million total (from EIA 2013b[5])
- Capacity factor: 30% (from EIA 2017)
- Life: 20 years (an assumption)
- Depreciation: assume straight-line depreciation, or $4.1 million per year
- Fixed O&M ($/kW-year): $7.34 (from EIA 2013b) or $0.6 million per year
- Variable O&M ($/MWh): $15.45 (from EIA 2013b) or $3.4 million per year
- Rate of Return: 9% (an assumption)

[5] The EIA values are in 2012$.

- Taxes: 20%[6] (an assumption)
- Rate Base: for simplicity, assume it just includes the net book value of the plant, and ignores other rate base components such as supplies and working capital.

The total base year revenue requirement is shown in Table 4.1.

Table 4.1. Revenue Requirement for Year 1 or Base Year

Rate Base (Million$)	Depreciation (Million$)	Return (Million$)	Fixed O&M (Million$)	Variable O&M (Million$)	Taxes (Million$)	Total (Million$)
$82.71	$4.14	$7.44	$0.62	$3.45	$1.86	$17.51

If you assume that fixed and variable O&M costs escalate at 2 percent per year in nominal dollars, the total PVRR after 20 years is $149 million.

4.2.5 Avoided Cost

4.2.5.1 Definition

Avoided cost is defined as the net change in the costs of the overall system with the development of the specified project. It can be a complicated calculation, subject to defining the boundaries of the analysis and adequately simulating the system. It captures items such as the energy avoided from other generators because of the new project (either a generator, demand response, or energy efficiency measures), capacity, substation, or transmission and distribution expansion.

4.2.5.2 Maturity Level

This metric is less mature than the other cost-effectiveness metrics described previously, partly because of the expanded simulation needed, but it has been used by utilities and regulators for several decades. Environmental assessments that include alternative ways to meet the needs of a project are a more generalized form of avoided cost analysis.

4.2.5.3 Applications

This metric has been used by utilities and regulators for establishing the value of a project compared to its alternatives and for setting the value of distributed generation technologies.

As will be seen in the Benefit Cost Analysis (BCA) metrics, the avoided cost is used for cost items within the BCA metrics. Various issues arise in such usage. One issue is that a single solar PV installation has a negligible impact on avoided capacity costs, whether it is generation, transmission, or distribution capacity. For example, when a 4 kW or 10 kW solar PV installation is compared to the megawatt capacity

[6] Most revenue requirement cost elements are deductible expenses for tax purposes. As a simplification, the example assumed the return on rate base represents net profit over and above direct expenses. Assuming that the return on rate base is intended to be an after-tax amount so the utility can pay bond holders and give a dividend to stock holders, the tax rate was used to calculate a gross-up formula or (1/(1-0.2)-1), which was multiplied by the return to yield the taxes due.

of even the smallest conventional generators, the impact is negligible. To actually avoid capacity costs, one needs to expect a number of solar PV installations. There are ways to estimate a capacity value. As an example, a utility could use a proxy value such as a conventional CT and assume that each kilowatt of capacity avoided is valued at the cost of that resource (PSE 2016). Some O&M costs like fuel or other consumables are clearly avoidable on a kilowatt-hour by kilowatt-hour basis. Fixed O&M costs are not dependent on the level of usage and are only avoidable if the utility can defer or avoid constructing a plant, but again there are ways to estimate an avoidable value (PSE 2016).

4.2.5.4 Example

The example used for the revenue requirements metric is a conventional CT. Assuming a conventional CT is a reasonable proxy for valuing DERs, what would the avoidable supply costs be for a solar PV installation that can deliver 4 kW into the system? For this example, the following assumptions are used:

- Capacity: Assuming a 14 percent capacity factor, the capacity value would be $136/kW.
- Fixed O&M: With the same capacity factor, the avoidable cost would be $1/kW-year.
- Variable O&M: With a 14% capacity factor, for each kilowatt of capacity the avoidable energy cost would be 1,227 kWh, which would be worth $19 at the variable O&M rate of $15.45/MWh.

4.3 Benefit-Cost Analysis Metrics

Five specific BCA (benefit-cost analysis) metrics are used extensively by utilities for analyzing resource options on the customer side of the meter. Perhaps the earliest and best-known documentation of the main BCA metrics is the California Standard Practice Manual (known as the Standard Practice Manual), first published in 1983 (CPUC 2001).[7] As noted by the American Council for an Energy Efficient Economy (ACEEE), virtually every state uses a version of one or more of the Standard Practices Manual BCA metrics (Kushler 2017). The use of the word "version" is key insofar as the Standard Practice Manual describes five metrics and defines inputs, but across the country, practitioners implement the metrics slightly differently.

BCA metrics are used for several purposes (Shenot et al. 2016), including the following:

- Screening of cost effectiveness: BCA metrics are used variously for determining the cost effectiveness of individual measures (changes to discrete pieces of equipment or elements of a building), programs (collections of related measures, e.g., all measures affecting residential building shells), or portfolios (collections of all programs offered).
- Potential studies: analyses of the potential impacts of DERs, including energy efficiency resources, in a utility territory.
- Integrated resource plans (IRPs): analyses used as input to IRPs where potential DER impacts are compared to supply-side resources and selected for implementation based on inclusion in a least-cost resource portfolio.
- Planning/procurement: utility practice, regulatory, or legislative requirement, wherein a utility uses BCA metrics to determine which resources to acquire; often a specific BCA metric is deemed to be

[7] Note that while the California Public Utilities Commission is not necessarily credited with being the first to devise the main cost tests, the Standard Practice Manual has long been viewed as the comprehensive documentation of the cost tests.

the primary metric for determining cost effectiveness, while others are used secondarily to help plan programs and determine incentive levels.

- Program evaluation: analyses after program implementation to measure actual energy or demand impacts of a program and actual program costs, using BCA metrics to determine if the actual program results approximated the pre-program expected results.

Each of the five main BCA metrics is based on costs and benefits measured from specific perspectives. The perspectives measured by BCA metrics include participants, non-participants, the utility, and society. In the vernacular of utility programs targeting the customer-side of the meter, participants are those customers who invest in DERs, including energy efficiency resources, or who otherwise elect to participate in utility incentive programs. Non-participants are those customers who elect to not participate in programs or invest in DERs. The utility also has a particular perspective. In all three cases, specific metrics measure the costs incurred and benefits received from the perspective of those bearing costs associated with the customer-side resource and receiving benefits generated by the resource.

The final perspective is that of society. This perspective is captured by two metrics. The first metric is a totaling of the participant and utility perspectives. Note that from this perspective, several costs or benefits disappear from the equation because they are, in effect, transfer payments and net to zero when the perspectives are totaled. The second societal metric adds in benefits and costs incurred by society at large—primarily non-monetary benefits in the form of positive externalities, e.g., reductions in greenhouse gas emissions. The Standard Practices Manual treats the two Societal Tests as variants of the same test (CPUC 2001). However, regulatory jurisdictions across the country treat the two high-level metrics as separate metrics (Shenot et al. 2016), and they are treated as separate metrics herein. The five widely used BCA metrics are the:

- Participant Test, and sometimes called the Participant Cost Test
- Ratepayer Impact Measure (RIM) Test, formerly the Non-Participant Test
- Program Administrator Cost Test, formerly known as the Utility Cost Test
- Total Resource Cost (TRC) Test
- Societal Cost Test (SCT).

In most states, utilities and regulators rely on one test as the primary test and others as secondary or additional tests. Generally, the primary test is used to determine whether a specific technology or portfolio of technologies is cost effective, i.e., it has a benefit-to-cost ratio greater than 1.0. The secondary tests are generally used to determine the maximum incentive payment the utility can offer to customers while still operating a cost-effective program. As of July 2017, 46 of the 51 states (the states plus the District of Columbia) used standard BCA metrics. Michigan uses a metric they designed. Of the states using standard BCA metrics (ACEEE 2017):

- 30 used the TRC Test or an adjusted TRC Test as their primary metric
- Of states using only one test:
  - 10 used only the TRC Test
  - 2 used only the SCT
  - 2 used only the Program Administrator Cost Test
  - 1 used only the RIM Test.
- 35 use multiple tests (2 or more) with 7 states using all 5 tests.

Table 4.2 lists each of the cost tests and the number of states using the metric as either their primary metric or as a primary or secondary metric.

Table 4.2. BCA Metrics Used as Primary and Secondary Metrics (ACEEE 2017)

Metric	Metric Used as Primary Metric	Metric Used as Primary or Secondary Metric
Total Resource Cost[(a)]	30	38
Program Administrator Cost[(a)]	5	29
Societal Cost	5	14
Ratepayer Impact Measure	2	26
Participant	0	22

(a) Idaho uses the TRC and Program Administrator Cost as its primary test, so Idaho was added into both totals.
Source: Analysis of data presented on the ACEEE website Evaluation, Measurement, & Verification.
http://database.aceee.org/state/evaluation-measurement-verification

An emerging version of the standard metrics is documented by the National Efficiency Screening Project (NESP). NESP defined the Resource Value Test (RVT), which NESP proposes to replace the standard cost tests. Because the RVT has yet to be adopted by any states for use, it will be treated as an emerging metric. However, NESP notes in their document that depending on a jurisdiction's goals, the RVT may or may not be different from the traditional metrics (NESP 2017).

The results can be stated in terms of NPV, benefit-cost ratios, discounted payback periods, or per-participant impacts. An alternative metric is a LCOE or capacity provided by the customer-side resource, which is useful in some analyses for comparisons with supply-side alternatives (CPUC 2001).

4.3.1 Participant Test

4.3.1.1 Definition

The Participant Test measures benefits and costs from the perspective of all utility customers who participate in the utility program. The test takes the following into account (CPUC 2001):

- Upfront equipment costs the customers might incur after subtracting any monetary incentives paid by the utility, including installation costs, removal of old equipment minus salvage value, sales tax, and (minus any) tax credits
- Customer time spent in arranging installations, if significant
- Avoided equipment costs in the form of the equipment options that were not chosen[8]

[8] The presumption is that energy efficient alternatives are more expensive than the less expensive options not chosen. So, the up-front capital cost is the cost differential between the efficient option that was chosen minus the less efficient option not chosen, after adjusting for taxes and tax credits, and taking into account the utility incentives. The cost test would also capture differential installation costs including the removal costs for the equipment being replaced as well as the customer's time spent arranging the installation if such is significant.

- Differential O&M costs including fuel costs.

Equations for the Participant Test metric are as follows (CPUC 2001):

$$NPV_P = TB_P - TC_P$$

$$NPV_{AveP} = (TB_P - TC_P)/P$$

$$BCR_P = TB_P/TC_P$$

$$DP_P = minimum\ years\ before\ TB_P \geq TC_P$$

where:

NPV_P = the net present value to all participants
TB_P = the total participant benefits discounted to Year 1
TC_P = the total participant costs discounted to Year 1
NPV_{AveP} = the net present value to the average participant
P = the number of participants
BCR_P = the benefit-cost ratio to participants
DP_P = the discounted payback in years.

The total participant benefits and total participant costs are further defined by the following equations:

$$TB_P = \frac{\sum_{t=1}^{N}(BR_t + TC_t + I_t)}{(1+d)^{(t-1)}}$$

where:

BR_t = the electric bill reductions in year t, including payments in the form of bill credits for energy provided to the electric grid
TC_t = the tax credits[9] received in Year t
I_t = the incentives[10] received in Year t
d = the customer discount rate
N = the number of years of the analysis; for a participant benefit it should include the expected lifetime of the DERs to capture all benefits.

$$TC_P = \frac{\sum_{t=1}^{N}(PC_t + BI_t)}{(1+d)^{(t-1)}}$$

where:

PC_t = the participant cost in Year t, including:

- Initial capital cost with sales tax,
- Installation cost less salvage value, and
- The value of the customer's time, if significant; it should include distribution system upgrade costs paid by the customer, if any.

[9] Local, state, and/or federal.
[10] Note that with DER such as solar photovoltaics or PV with battery storage, incentives might come from utilities or from other sources such as state government-funded non-utility programs.

In some cases, customers might receive ongoing incentive payments from a utility to participate in a DER program. The broad definition of DERs includes load control programs in which utilities typically offer customers a set incentive, e.g., $20 per month for the summer months for air conditioner load control. In other cases of DERs, e.g., distributed (solar) generation, customers receive credits from the utility for energy injected into the grid, and the customer benefits from any behind-the-meter generation used by the customer in lieu of purchases from the utility. Whether the DER benefits are categorized as bill reductions or as incentive payments is not necessarily important in the Participant Test, but all such benefits must be captured to obtain an accurate picture of the total participant benefits.

When calculating initial capital costs, the cost of equipment that would otherwise be installed should be considered. In the case of an energy efficient appliance, the customer would presumably purchase an appliance regardless, so the initial capital cost would be estimated as the difference between the installed cost of the efficient appliance and the appliance the customer would otherwise purchase. In the case of a DER such as rooftop solar photovoltaic (PV) generation, there might not otherwise be equipment purchased, so the purchase cost might accurately be the total purchase and installation cost.

4.3.1.2 Maturity Level

Mature. The Participant Test has been continuously in use since at least the publication of the Standard Practices Manual. There is little or no evidence in the literature of the Participant Test being used specifically for DER analyses other than demand-side management (DSM) and energy efficiency (Shenot et al. 2016). The Participant Test is used exclusively as a secondary test.

4.3.1.3 Applications

Utilities use the Participant Test to identify the desirability of a proposed program to customers. It is a tool used to help utilities to set the incentive levels for programs and to gauge expected participation rates. The drawback is that this tool does not in any way attempt to model customer behaviors in response to a proposed incentive level, so interpreting the results of the Participant Test requires judgment on the part of the analysts using the test for new programs.

The metric is also applicable for post-program evaluations to determine whether customers received a positive or negative return on their investments in customer-side resources.

4.3.1.4 Example

The following is an example of customers purchasing rooftop solar PV. Note that the descriptions of BCA metrics discuss performing the analysis at a program level. In this document, the examples given are looking simply at one installation rather than at several thousands (or millions) of installations spread over a program lifetime.

The customer faces upfront capital costs to purchase and install the system, including some costs assessed by the utility for the integration of the solar PV system into the distribution grid. The customer receives several benefits including state and federal tax credits, and at least for this example, a net energy metering credit for energy exported to the grid and the avoidance of retail energy purchase costs to the extent the customer uses the energy rather than exporting it.

The example again uses assumptions based upon the Consolidated Edison BCA Handbook (ConEd 2016) supplemented with a report prepared for the New York Energy Research and Development Authority and

New York State Department of Public Service by Energy + Environmental Economics (E3 2015). The assumptions are as follows:

- Time period – 20 years, 2016 to 2035
- Installed cost (2015$/kW –AC) – $4,430
- Project size (AC) – 4 kW
- Assuming a 14% capacity factor, the unit generates 1,190 kWh/kW-DC
- Conversion factor, DC to AC – 95%
- Fixed operating cost (2015$/kW) – $15
- Tax credits – total of 55 percent, 30% federal and 25% state
- Assumed the customer purchases with cash, so financing carrying costs not an issue
- Base year net energy metering credit (2015$/kWh) – $0.22
- Discount rate – 5%
- General, overall inflation – 2%
- Incentives from utility – none.

The analysis was performed using nominal dollars and a nominal discount rate. Assuming the consumer has no additional costs beyond the installation and fixed operation cost, the 20-year lifetime benefits and costs, discounted to 2016 are as follows:

- Benefits – $15,443
- Costs – $8.947
- Benefit-cost ratio – 1.7
- Net present value of benefit – $6,497.

With the resulting participant benefit-cost ratio, the electric utility might not be inclined to offer additional incentives. If or when tax credits are ended, a utility might then be inclined to investigate incentives to keep customers installing solar PV.

4.3.2 Ratepayer Impact Measure Test

4.3.2.1 Definition

The RIM Test measures the impact on customer bills that result from a utility attempting to “build” a demand-side resource. For the RIM Test, benefits include avoided supply costs (i.e., avoided transmission, distribution, generation, and capacity costs) for the time period over which the demand-side resource reduces such costs, thereby yielding the savings. Costs include all utility costs and costs incurred by others who might create or administer programs for the utility, incentives paid to participants, and decreased revenues for the entire time period during which the program decreases revenues. Both the revenue loss and supply cost savings should be calculated using net program energy savings, or program energy savings minus those that would have occurred if the program did not exist (CPUC 2001).

The RIM Test is calculated as follows (CPUC 2001):

$$B_{RIM} = \frac{\sum_{t=1}^{N}(UAC_t + ER_t)}{(1+d)^{(t-1)}}$$

where:

B_{RIM} = benefits included in the RIM calculations
UAC_t = utility avoided supply cost in Year t. Supply costs should be interpreted to mean not just marginal power supply costs but also where applicable marginal transmission and distribution costs.
ER_t = environmental regulation costs avoided or credits associated with use of renewable resources or energy storage, to the extent that such costs/credits are direct costs avoided or credits obtained, as opposed to non-monetized societal benefits.[11]
d = discount rate; weighted average cost of capital for the utility.

The BCA metric treatment of energy storage, solar PV, and other DERs will vary based on the characteristics and use of the DER. For example, energy storage charged by solar PV on the customer side of the meter could provide the same system benefits to the utility as a storage system charged during off-peak hours by generation located on the grid. Both systems would provide different benefits than a system charged by generation on the grid with no regard for on-peak versus off-peak timing, or a system charged with wind generation only.

The cost side of the test is estimated as follows (CPUC 2001):

$$C_{RIM} = \frac{\sum_{t=1}^{N}(UIC_t + DS_t + RL_t + PRC_t + Inc_t)}{(1+d)^{(t-1)}}$$

where:

C_{RIM} = costs included in the RIM calculations
UIC_t = utility increased supply cost in Year t; DER options can have positive supply benefits but also cause ongoing supply (ancillary service) costs
DS_t = distribution system upgrade costs paid by the utility, primarily in Year 1[12]
RL_t = revenue losses in Year t
PRC_t = program administrative cost in Year t
Inc_t = incentives paid by the utility in Year t.

The main metrics include the following:

BCR_{RIM} = B_{RIM}/C_{RIM}
NPV_{RIM} = B_{RIM} - C_{RIM}

[11] While the costs of some environmental regulations are embodied in avoided supply costs, e.g., pollution abatement costs embedded in the cost of power from fossil generation, avoidable costs such as purchasing carbon allowance credits or benefits such as tradeable renewable energy credits should arguably be included to the extent that they are real, direct costs avoided or credits acquired (Shenot et al. 2017).
[12] Distribution system costs are shown separately here. The Standard Practices Manual formulas may have implicitly included distribution system costs, although at the time of the last update the manual would likely not have contemplated DER options such as solar PV or electric vehicles (EVs), which might require distribution system expenditures to make installations possible.

$$LRI_{RIM} = (B_{RIM} - C_{RIM})/E$$

where

$$LRI = \text{life-cycle revenue impact per unit of energy (E)}$$
$$FRI_{RIM} = (C_{RIM} - B_{RIM})/E \text{ for year} = 1$$

where

$$FRI = \text{the first-year revenue impact}$$
$$ARI_{RIM} = (C_{RIM} - B_{RIM})/E \text{ for year} = 1 \ldots N$$

where

ARI = the average revenue impact of RIM, and where the stream of annual impacts is not discounted.

Thus, ARI_{RIM} for Year = 1 would equal FRI_{RIM}.

4.3.2.2 Extensions of the RIM

While state regulators continue ramping up the use of BCA metrics for DERs such as solar PV, electric vehicles (EVs), batteries and other storage, and combined heat and power, collaborative efforts are under way to identify cost and benefit elements for the metrics. Currently, no documentation of explicitly labeled extensions of the RIM have been identified. However, Value of DER and Value of Solar—the so-called successor tariffs to net energy metering—have focused attention on identifying the impact on non-participating customers (E3 2017).

4.3.2.3 Maturity

Mature. As was shown in Table 4.2, the RIM is used in 26 states. Note though that the RIM is largely a secondary metric—of 26 states using the RIM, only 2 states use fewer than three tests. Virginia lists the RIM as their primary metric, but in 2012 adopted a new rule saying that no program would be rejected based on only one test (ACEEE 2017).

4.3.2.4 Applications

The primary application would be a situation where equity considerations in the distribution of costs and benefits are a major concern. A utility program offering incentives for installation of solar PV will result in a reduction in energy sales and a reduction in energy revenues. The resulting lost revenues may need to be made up by ratepayers, in the form of a rate increase, to produce the same level of revenues with lower kilowatt-hour sales. The RIM is the only test that reflects this revenue distribution (CPUC 2001).

The RIM is the only BCA metric that measures the impact on rates but does not tell us if a DER program is in best interests of the public (Shenot et al. 2016). This point is particularly important when a utility is examining DER programs that utilities have been directed legislatively to implement. However, as a secondary metric, the RIM might be useful in program design to minimize impacts on non-participants.

The RIM Test is the only standard cost test that includes lost revenues in the calculation. Energy efficiency advocates have long pointed out an inconsistency in basing resource decisions on the RIM Test. Namely, as described by NESP, supply-side resources do not cause lost revenues. However, they put upward pressure on rates. A demand-side resource may be more cost effective than a supply resource but may be rejected based on a RIM Test (NESP 2017). An additional caution related to use of the RIM is the issue of basing decisions on sunk costs. The upward rate pressures caused by energy efficiency (or by solar PV-incentivization) programs results from fewer kilowatt-hour sales being available to recover the costs of existing facilities. In other words, the costs are essentially sunk costs, and sunk costs should not be used as a basis for future resource decisions (Woolf et al. 2014).

4.3.2.5 Example

For the RIM, again, costs were based on the Consolidated Edison (ConEd 2016) and E3 reports (E3 2015). Additional information was obtained from a spreadsheet obtained from the New York Public Service Commission (NYPSC) containing projections of the Annual Avoided Generation Capacity Costs (NYPSC 2016a); from a New York Independent System Operator (NYISO) presentation that contained projections of locational energy prices (NYISO 2015); and from the NYPSC BCA Order (NYPSC 2016b). Note that while this example attempts to use values representative of the Consolidated Edison service area, the example shown below is a significantly simplified example and some values are at best approximations.

Benefits:

- All solar PV facility descriptors are derived from the Participant Cost Test example.
- Coincidence factors for the system (35%), transmission (8%) and distribution (7%) are from the Consolidated Edison report.
- Projected locational prices in $/MWh are taken from NYISO (2015), using the Dunwoodie price location.
- Avoided Generation Capacity Costs are from the NYPSC using the Lower Hudson Valley zone.
- Marginal transmission and distribution capacity values are from the Consolidated Edison report as are fixed and variable loss factors.
- Hedging benefits were not identifiable from the information available, hedging benefit is left as $0 though it is likely a benefit is possible.
- Weighted average cost of capital is used for the discount rate set to 6.91 percent.
- Costs include:
  - Lost revenues derived from the Participant Cost Test example
  - Program administration assumed to cost $3/MWh per year, escalating with inflation
  - Integration costs assumed also to cost $3/MWh per year, escalating with inflation
  - A system upgrade cost of $500/kW assumed for Year 1; assumed to not be a physical part of the interconnection of the solar PV to the grid, but rather other system-wide upgrades allocated to the unit—costs such as a distribution control system, line or other reinforcements elsewhere on the grid, and other non-project specific costs incurred more generally to make DERs possible (purely an assumed value insofar as no estimates of this value were found in the literature)
  - No incentives assumed other than NEM payments and the lost revenue.

With the information available, it was possible to determine utility benefits for avoided capacity, avoided energy, and transmission and distribution capacity credits. Following the E3 example, ancillary service benefits were assumed to be 1 percent of energy benefits given a lack of clear expectations concerning the extent to which solar PV systems will be equipped to provide ancillary services. For this example, it was assumed that several possible system benefits would be zero. Transmission and distribution system loss benefits were assumed to be $0 because it is not clear that a solar PV installation will have an impact on the percentage loss factors (note that the energy and capacity benefits include losses explicitly). Similarly, it seemed unlikely that solar PV would have an impact on distribution system O&M and on outage rates, so these possible benefits were assumed to be $0.

The 20-year lifetime benefits and costs, discounted to 2016 are as follows:

- Benefits – $6,748
- Costs – $15,714
- Benefit-cost ratio – 0.4
- Net present value of benefit – $(8,966).

The negative results are entirely generated by the lost utility revenues. Excluding the lost revenues, this assumed solar PV system has a positive benefit to the utility.

4.3.3 Program Administrator Cost Test

4.3.3.1 Definition

The Program Administrator Cost (PAC) Test, aka, the Utility Cost Test or UCT, includes all of the costs and benefits from the perspective of the utility system. The PAC differs from the RIM Test by the exclusion of the lost revenues included in the RIM. In the PAC, the impacts on rates are not considered a "cost" as was the case with the RIM Test. Rather, the impacts are considered a transfer payment between ratepayers and program participants (the costs incurred by non-participants equal the benefits experienced by participants). The results can be viewed as NPV, a benefit-cost ratio, or as levelized costs (CPUC 2001).

The PAC Test is calculated as follows (CPUC 2001):

$$B_{PAC} = \frac{\sum_{t=1}^{N}(UAC_t + ER_t)}{(1+d)^{(t-1)}}$$

where:

B_{PAC} = benefits included in the PAC calculations
UAC_t = utility avoided supply cost in Year t. Supply costs should be interpreted to mean not just marginal power supply costs but also where applicable marginal transmission and distribution costs.
ER_t = environmental regulation costs avoided or credits associated with use of renewable resources or energy storage, to the extent that such costs/credits are direct costs avoided or credits obtained, as opposed to non-monetized societal benefits.[13]
d = discount rate; weighted average cost of capital for the utility.

$$C_{PAC} = \frac{\sum_{t=1}^{N}(UIC_t + DS_t + PRC_t + Inc_t)}{(1+d)^{(t-1)}}$$

[13] Section 4.3.3.2 provides additional discussion of this topic.

where:

C_{PAC} = Costs included in the PAC calculations
UIC_t = utility increased supply cost in Year t; DER options can have positive supply benefits but also cause ongoing supply (ancillary service) costs
DS_t = distribution system upgrade costs paid by the utility, primarily in Year 1[14]
PRC_t = program administrative cost in Year t
Inc_t = incentives paid by the utility in Year t

Main metrics include:

$$BCR_{PAC} = B_{PAC}/C_{PAC}$$
$$NPV_{PAC} = B_{PAC} - C_{PAC}$$
$$LRI_{PAC} = (B_{PAC} - C_{PAC})/E$$

where

LRI = life-cycle revenue impact per unit of energy (E).

4.3.3.2 Extensions of the Program Administrator Cost Test

Several states have undertaken or are currently undertaking analyses referred to as Value of Solar (VOS) or Value of DER studies. To date, the VOS analyses have been proposed/performed as a tool for setting payment levels for solar PV as replacements for NEM tariffs. Value of DER analyses have likewise been geared toward identifying the value for purposes of setting values for tariff purposes. Perhaps because the VOS/Value of DER studies have been geared toward tariffs, models proposed thus far have resembled an adjusted PAC Test, insofar as they have quantified utility costs and benefits, and excluded the customer costs and benefits associated with the DER.

The main adjustments made to the PAC have been to include additional emissions valuation components. Because DERs in general can provide significant environmental benefits, much attention focuses on quantifying renewable energy credits (RECs) or otherwise quantifying credit toward renewable portfolio standards (RPSs). In their Phase One successor tariffs to replace NEM tariffs, the State of New York includes components related to REC/RPS credits and a Social Cost of Carbon component, as well as safeguards to prevent double counting of RECs (NYPSC 2017).

While not exactly a change, the VOS and Value of DER studies include careful enumeration of ancillary service costs and benefits associated with DERs. For example, the Minnesota VOS and Oregon VOS methodologies both specifically mention integration costs such as reserves for frequency regulation or to cover variability in solar output, although at least initially the Minnesota VOS methodology sets this component to $0 (OPUC 2017; MDOC 2014).

4.3.3.3 Maturity

Mature. The PAC Test (or UCT as it is frequently called), is used in 29 states—making it second only to the TRC Test, which is used in 38 states.

[14] Distribution system costs are shown separately here. The Standard Practices Manual formulas may have implicitly included distribution system costs, although at the time of the last update the manual would likely not have contemplated DER options such as solar PV or EVs, which might require distribution system expenditures to make installations possible.

4.3.3.4 Applications

In theory, the PAC Test measures all costs and benefits from the utility perspective. The PAC Test is the metric that comes closest to reflecting the traditional regulatory approach to minimizing long-term revenue impacts of resource acquisition. By focusing strictly on the costs and benefits from the utility or program administrator perspective, the PAC Test allows direct comparison to supply resources, and allows development of DER acquisition policies predicated on incentives equal to or less than the value of DERs to the utility. For utilities with limited funds to spend on incentive programs, the PAC Test assists in focusing on the programs providing the best benefit to the utility. The PAC Test avoids use of "more difficult to quantify" costs and benefits including participant costs and benefits as well as non-energy benefits, thus making the test easier to administer and less contested (Shenot, et al. 2016).

4.3.3.5 Example

Using the information from the RIM Test example, the only additional assumption made for the PAC Test is that of the estimation of the solar PV system energy generation—20 percent is exported to the system and the remainder is used by the customer. Thus, 80 percent of the solar PV represents lost revenue to the utility but not a direct, out-of-pocket payment to the customer.

The 20-year lifetime benefits and costs, discounted to 2016 are as follows:

- Benefits – $6,748
- Costs – $5,034
- Benefit-cost ratio – 1.3
- Net present value of benefit – $1,714.

Note that with a "surplus" per unit of $1,714, if the tax credits were lowered relative to the levels hypothesized for the Participant Test, the utility could consider an upfront incentive to induce customers to continue installing solar PV.

4.3.4 Total Resource Cost Test

4.3.4.1 Definition

The Total Resource Cost Test, or TRC Test, measures the cost of programs using a combination of the participant and non-participant perspectives. The costs included in the program include the costs incurred by the utility to operate the program and all participant costs. Thus, the total cost of equipment is included regardless of whether the utility pays for it with incentive or rebate payments, or whether the customer pays for it, excluding any applicable tax credits. Within the TRC Test calculation, incentive/rebate payments are a transfer payment and net to zero. Benefits include avoided supply costs, calculated using net program savings. The impacts can be expressed as NPV, B-C ratio, or as a levelized cost (CPUC 2001).

The TRC Test is calculated with the following formulas (CPUC 2001):

$$B_{TRC} = \frac{\sum_{t=1}^{N}(UAC_t + TC_t + ER_t)}{(1+d)^{(t-1)}}$$

where:

B_{TRC} = benefits included in the TRC Test calculations
UAC_t = utility avoided supply cost in Year t. Supply costs should be interpreted to mean not just marginal power supply costs but also where applicable marginal transmission and distribution costs.
TC_t = tax credits in Year t
ER_t = environmental regulation costs avoided or credits in Year t, to the extent that such costs/credits are direct costs avoided or credits obtained, as opposed to non-monetized societal benefits[15]
d = discount rate; weighted average cost of capital for the utility.

$$C_{TRC} = \frac{\sum_{t=1}^{N}(UIC_t + DS_t + PCN_t + \ PRC_t)}{(1+d)^{(t-1)}}$$

where:

C_{TRC} = Costs included in the TRC Test calculations
UIC_t = utility increased supply cost in Year t; DER options can have positive supply benefits but also cause ongoing supply (ancillary service) costs
DS_t = distribution system upgrade costs paid by the utility, primarily in Year 1[16]
PCN_t = net participant costs (equipment cost, installation costs less salvage value of equipment being replaced, plus customer time in arranging the installation – if significant)
PRC_t = program administrative cost in Year t.

Main metrics include:

BCR_{TRC} = B_{TRC}/C_{TRC}
NPV_{TRC} = B_{TRC} - C_{TRC}.

4.3.4.2 Extensions of the Total Resource Cost Test

As discussed in Section 4.3, several states use an adjusted TRC Test, primarily with an addition of environmental costs above and beyond those embodied in direct costs. For example, Illinois uses a TRC with some societal cost components included (ACEEE 2017).

Because the TRC Test is widely used, it seems likely that as utilities continue implementing, planning for, and evaluating more and more programs involving solar PV, energy storage, and EVs, combined heat and power (CHP), and other DERs beyond traditional energy efficiency and DSM, more states will be using adjusted TRC Tests. No documentation has been identified yet that makes clear that an adjusted TRC Test has been explicitly used with a Value of DER or VOS process. This emerging metric aspect of the TRC Test/SCT is discussed further in Section 4.3.5.

[15] While the costs of some environmental regulations are embodied in avoided supply costs e.g., pollution abatement costs embedded in the cost of power from fossil generation, avoidable costs such as purchasing carbon allowance credits or benefits such as tradeable renewable energy credits should arguably be included to the extent they are real, direct costs avoided or credits acquired (Shenot et al. 2017).
[16] Distribution system costs are shown separately here. The Standard Practices Manual formulas may have implicitly included distribution system costs, although at the time of the last update the manual would likely not have contemplated DER options such as solar PV or EVs, which might require distribution system expenditures to make installations possible.

4.3.4.3 Maturity

Mature. The TRC Test is used in 38 states, and 30 states use either the TRC Test or an adjusted TRC Test as their primary cost test.

4.3.4.4 Applications

As suggested by the word Total, the TRC includes all costs and benefits and as a result the TRC provides a snapshot of the complete and direct impacts of the demand-side resource being studied. Because it includes all costs and excludes questions about the distribution of the benefits caused by incentives, the TRC Test provides a more complete picture of DER cost effectiveness than does the PAC Test, which only looks at the utility costs and benefits (Shenot et al. 2016). To the extent supply resource costs include all relevant costs including transmission costs, the TRC Test provides a good basis for comparison to supply resources (CPUC 2001). As noted above, the TRC Test is used in 30 states as the primary cost test.

4.3.4.5 Example

Using the information developed for the earlier tests, benefits include all those included in the RIM and PAC Tests plus the tax credits, which are treated as a benefit. The costs include program administration, integration, system upgrades, and the upfront capital cost of the equipment.

The 20-year lifetime benefits and costs, discounted to 2016 are as follows:

- Benefits – $16,494
- Costs – $20,084
- Benefit-cost ratio – 0.8
- Net present value of benefit – $(3,590).

4.3.5 Societal Cost Test

4.3.5.1 Definition

The SCT analyzes demand-side options from the societal perspective. Given the broader societal viewpoint, some items included in other cost tests like tax credits are eliminated because they are transfer payments. The impacts from this broader perspective and the inclusion of societal impacts or externalities differentiate the SCT from the TRC Test. In the CPUC formulation of the cost tests, the differences between the TRC Test and the SCT include (CPUC 2001) the following:

- The use of higher marginal costs if the utility performing the analysis uses marginal costs in the TRC Test that are lower than costs faced by utilities elsewhere in the state or lower than the utility's out-of-state suppliers
- The fact that from a societal perspective tax credits are transfer payments and as such are not included in the SCT
- The treatment of interest payments as transfer payments, meaning that the SCT treats the capital costs as first-year expenses and not as a payment stream amortizing the expenditure over time
- The use of a societal discount rate rather than a utility weighted average cost of capital

- The inclusion of externality costs of power generation not captured within the power cost.

As discussed in the emerging cost tests for Solar and DERs, the SCT is being investigated for use by states for DER options beyond energy efficiency and DSM programs. An important part of these discussions is which externality costs to include. Some externalities are directly related to energy usage or generation, such as emissions not internalized by emissions control technologies installed on electric generation stations or purchase of emissions credits. Other externalities are direct and relatively quantifiable but non-energy impacts, such as water savings accruing from the use of more energy efficient clothes washers.[17] Still others are non-energy benefits that are difficult to quantify, such as health impacts from reduced emissions or from increased comfort levels in low-income housing targeted by low-income programs. Lazar and Colburn (2013) document a lengthy list of possible non-energy impacts (NEIs) that could be included.

States incorporate NEIs to varying degrees, and some states use modified TRC Tests rather than SCTs. In its TRC Test, Oregon includes NEIs such as the participant water savings when they can be easily quantified and are significant, and a 10% benefit adder for energy efficiency programs to account for "risk, uncertainty, and known but difficult-to-quantify benefits" (Shenot et al. 2016). California on the other hand attempts to isolate only the energy-related costs and benefits, so in the example of the clothes washer, California would attempt to isolate the energy-related incremental equipment costs from the water-saving equipment costs. Thus, California would exclude both the non-energy costs and benefits (Shenot et al. 2016).

The SCT is calculated using the following formulas (CPUC 2001):

$$B_{ST} = \frac{\sum_{t=1}^{N}(UAC_t + ER_t + \ EXT_t)}{(1+d)^{(t-1)}}$$

where:

B_{SC}	=	benefits included in the Societal Cost test calculations
UAC_t	=	utility avoided supply cost in Year t. Supply costs should be interpreted to mean not just marginal power supply costs but also where applicable marginal transmission and distribution costs.
ER_t	=	environmental regulation costs avoided or credits in Year t, to the extent that such costs/credits are direct costs avoided or credits obtained, as opposed to non-monetized societal benefits.[18]
EXT_t	=	external benefits such as environmental benefits not captured as a direct benefit
d	=	discount rate; societal rate, frequently assumed to be 3 or 7 percent.

$$C_{SC} = \frac{\sum_{t=1}^{N}(UIC_t + DS_t + PCN_t + \ PRC_t)}{(1+d)^{(t-1)}}$$

where:

[17] Because water cost is an O&M cost to participants in programs, this would/should be captured within the tests that capture participant benefits.

[18] While the cost of some environmental regulations are embodied in avoided supply costs, e.g., pollution abatement costs embedded in the cost of power from fossil generation, avoidable costs such as purchasing carbon allowance credits or benefits such as tradeable renewable energy credits should arguably be included to the extent they are real, direct costs avoided or credits acquired (Shenot et al. 2017).

C_{SC} = costs included in the Societal Cost test calculations
UIC_t = utility increased supply cost in Year t; DER options can have positive supply benefits but also cause ongoing supply (ancillary service) costs
DS_t = distribution system upgrade costs paid by the utility, primarily in Year 1[19]
PCN_t = net participant costs (equipment cost, installation costs less salvage value of equipment being replaced, plus customer time in arranging the installation – if significant)
PRC_t = program administrative cost in Year t.

Main metrics include:

$$BCR_{RIM} = B_{RIM}/C_{RIM}$$
$$NPV_{RIM} = B_{RIM} - C_{RIM}.$$

4.3.5.2 Extension of Societal Cost Test

The SCT—or an adjusted TRC Test—is a likely candidate to form the basis of BCA metrics used for DERs such as solar PV, energy storage, and others such as EVs. As noted in Section 4.3.5.1, there are differences between an adjusted TRC Test and the SCT, including the discount rate used and whether or not some costs are treated as transfer payments and dropped from the benefit or cost stream.

The CPUC staff proposed a SCT for determination of the Value of DERs (CPUC 2017a). CPUC staff proposed two environmental benefits adders. The first adder is a greenhouse gas adder to be used in the avoided cost calculator when analyzing the cost effectiveness of DERs (CPUC 2017b). The second is to monetize reductions in high global warming potential refrigerants or methane (CPUC 2017a).

While the NYPSC value of DERs cited in Section 4.3.3.2 is a variant of the PAC, the NYPSC's BCA order sets the SCT as the primary test for determining the cost effectiveness of DERs, with the PAC and RIM Tests as secondary tests. The PAC and RIM Tests are used to identify projects needing a closer examination. Projects passing the SCT but not the PAC and RIM Tests are not rejected unless a complete bill analysis shows impacts of unacceptable magnitude (NYPSC 2016b).

4.3.5.3 Maturity

Mature. While inclusion of NEIs evolves and differs widely, the SCT has been in use for as long as the other tests. The SCT is used in 14 states and is the primary test in 5 states.

4.3.5.4 Application

The SCT is an all-inclusive test like the TRC Test, and because it explicitly attempts to quantify externalities such as emissions, it may be the best cost test for comparison to supply-side resources.

4.3.5.5 Example

Using information developed in the earlier tests, the SCT includes the program administrative costs, integration costs, system upgrades, and the upfront cost of the solar PV. The benefits include the same

[19] Distribution system costs are shown separately here. The Standard Practices Manual formulas may have implicitly included them, although at the time of the last update the manual would likely not have contemplated DER options such as solar PV or EVs, which might require distribution system expenditures to make installations possible.

benefits used in the RIM Test (i.e., the same benefits included in the TRC Test excluding the tax credits, which are considered transfers within society) plus the non-energy benefits monetized in the analysis. In this example, an additional benefit associated with carbon dioxide was included. The emissions benefit is in addition to the avoided emissions costs embodied in the supply costs. It was assumed to be $35 per MWh in 2016, escalating with inflation.

The 20-year lifetime benefits and costs, discounted to 2016 are as follows:

- Benefits – $12,431
- Costs – $20,218
- Benefit-cost ratio – 0.6
- Net present value of benefit – $(7,787).

Note that the TRC Test treats tax credits as a benefit. From a utility perspective, tax credits are "imports" to the system, whereas some non-energy benefits like the additional emissions benefit are created by the changes made by the utility system. Thus, if one uses an adjusted TRC Test rather than a SCT, the results would appear better than the results using the SCT.

4.3.6 Resource Value Test

4.3.6.1 Definition

The RVT is a recently proposed cost test metric from a regulatory perspective. As NESP notes, regulators are specifically charged with ensuring utilities provide customers with safe, reliable, and low-cost service, while at the same time meeting other policy goals that might be imposed legislatively or through the regulatory process. There are abundant examples of other policy goals, such as ensuring utilities meet goals for renewable energy or greenhouse gas emissions reductions. Thus, a major thrust of the NESP is to describe a Resource Value Framework (Framework) to assist regulators in capturing the impacts of all policy goals (NESP 2017).

Rather than formulas, the Framework proposes guidance on how to develop cost-effectiveness tests. NESP does this by proposing a step-by-step process (presented below) for identifying the policy goals and the costs and benefits that the policy goals would imply need to be included, and for developing inputs for the RVT (NESP 2017).

1. Identify all applicable policy goals.
2. Include all utility-system costs and benefits (the same costs and benefits identifies for the standard cost tests).
3. Decide which NEIs are required to quantify the policy goals.
4. Ensure symmetry in the cost test by considering costs and benefits.
5. Ensure the cost test and underlying analyses are forward looking and incremental.
6. Develop methods for quantifying all costs and benefits, including the hard-to-quantify impacts.
7. Ensure transparency in the presentation of inputs and results.

As the list of steps indicates, the NESP focuses heavily on identifying all relevant impacts, and including all such impacts—even the hard-to-quantify impacts. In this way, NESP differs at least somewhat from the benefit-cost analyses seen around the country.

4.3.6.2 Applicability

Because all state regulators operate within a legislative and regulatory framework that makes them responsible for making operational a potentially wide and divergent set of policy goals, the RVT and Framework are potentially applicable in every state. It is easy to dismiss the proposal with a statement like "we're already doing this; there's nothing new here." However, it is also possible to find examples where this is not the case. For example, while researching potential methodologies for valuing DERs, CPUC staff found that a clear legislative policy goal favoring greenhouse gas reductions had never been operationalized in the form of a clear and consistent implementation of a SCT (CPUC 2017a).

4.3.6.3 Maturity

Emerging to Mature. NESP offers several practical steps for developing a Framework and for quantifying the hard-to-quantify benefits and costs. However, the Framework presents a new way of looking at the tools and methods that are used today in jurisdictions across the country. Thus, while the tools are mature, the tools are put together in a way that makes this a potentially emerging methodology.

4.3.6.4 Example

The results of an example for the RVT would be the same as any of the earlier cost tests, with the addition of hard-to-quantify benefits (or costs). Taking the example given by various states, hard-to-quantify benefits can be included by way of an adder or multiplier applied to the other, quantifiable benefits. In effect, leaving the benefits out is tantamount to saying they do not exist. Rather, some states have said the opposite—we know they exist, but we cannot quantify them, so we propose applying a 10 percent adjustment to quantifiable DER benefits. This could be applied to any cost test. Thus, applying it to the TRC metric, the 20-year lifetime benefits and costs, discounted to 2016 are as follows:

- Benefits – $18,143
- Costs – $20,084
- Benefit-cost ratio – 0.9
- Net present value of benefit – $(1,941).

4.4 Macro Indicators of Electricity Affordability

Some indication of the state of electricity affordability can be seen in components of the macroeconomic measures reported in the accounting of gross domestic product. The Department of Commerce's Bureau of Economic Analysis (BEA) maintains the National Income and Product Accounts (NIPA), which track the components of gross domestic product. Several monthly, quarterly and annual series are maintained and reported by BEA.

Objective of this analysis was to see not only how affordability differs across states for firms within the same industry but also to show how affordability varies by industry itself. The first indicator is given by the green line in Figure 4.1 and represents the proportion of total personal consumption expenditures spent on electricity. Over the period (2002 – 2018), this indicator has declined, albeit very minimally (from a high of 1.69 percent to a low of 1.31percent) and has on an average remained at 1.5 percent.

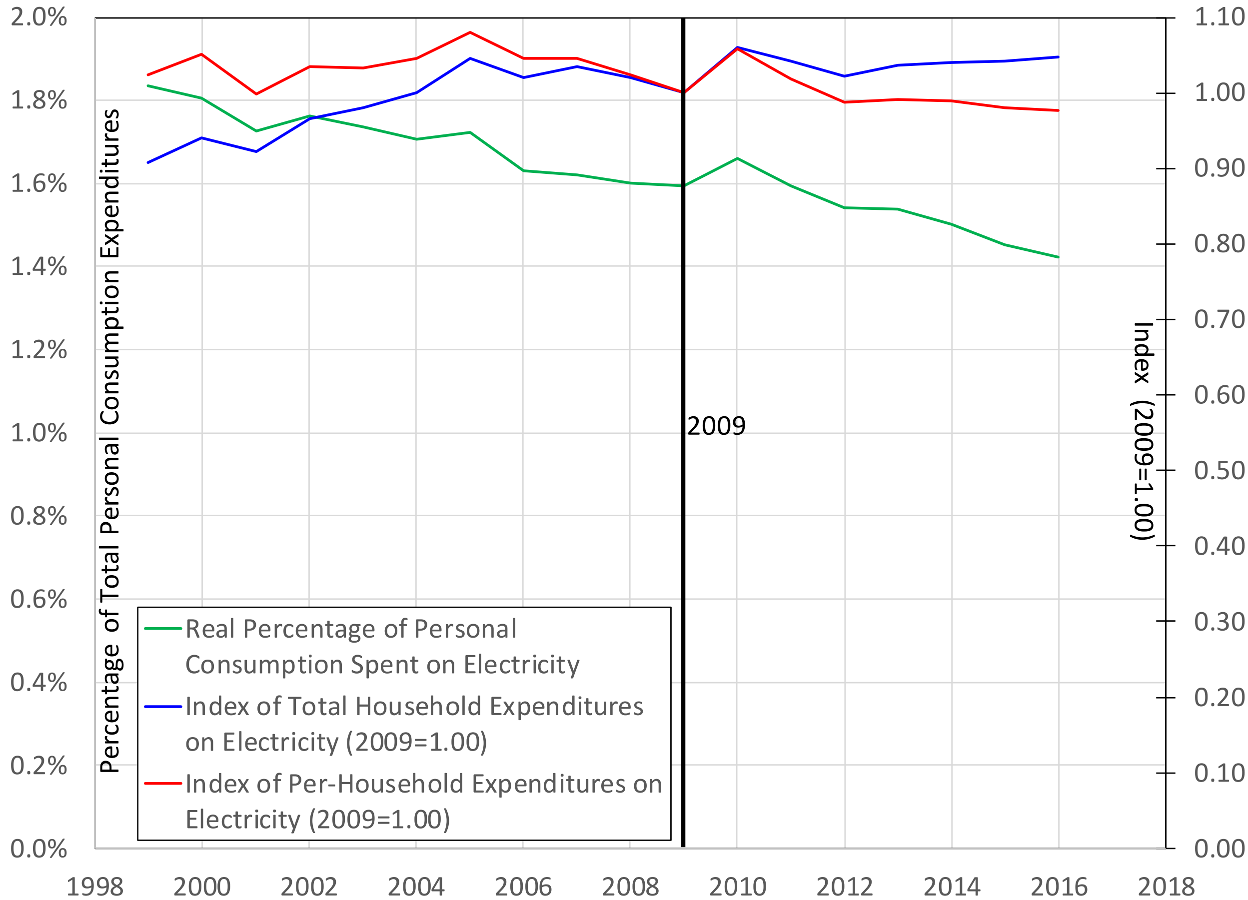

Figure 4.1. Macroeconomic Indicators of Electricity Affordability Based on National Income and Product Accounts

On the surface, this would suggest that electricity has become more affordable, but a further analysis of the data reveals something different. The growth rate of real personal consumption expenditure on electricity has registered an average growth rate of 0.62 percent during the same period. In comparison, the growth rate of real personal consumption expenditure, has registered an increase (from a low of -1.75 percent during the peak of the recession in 2009 to a high of 3.79 percent), averaging 2.11 percent over the same period. This suggests that real personal consumption expenditures have grown at about 3.4 times the real personal consumption expenditure on electricity, which is why the share of electricity in total personal consumption expenditure appears as a declining trend.

Further, comparing the real personal consumption expenditure on electricity with the real personal consumption expenditure excluding food and energy, both as a share in total real personal consumption expenditure (all adjusted to $2012), as shown in Figure 4.2, (BEA 2017) shows that the declining share of real personal consumption expenditures on electricity has been replaced by an increasing share in other durables and non-durables (excluding food and energy).

In other words, a declining trend in the proportion of total personal consumption expenditure on electricity does not imply that electricity has become more affordable.

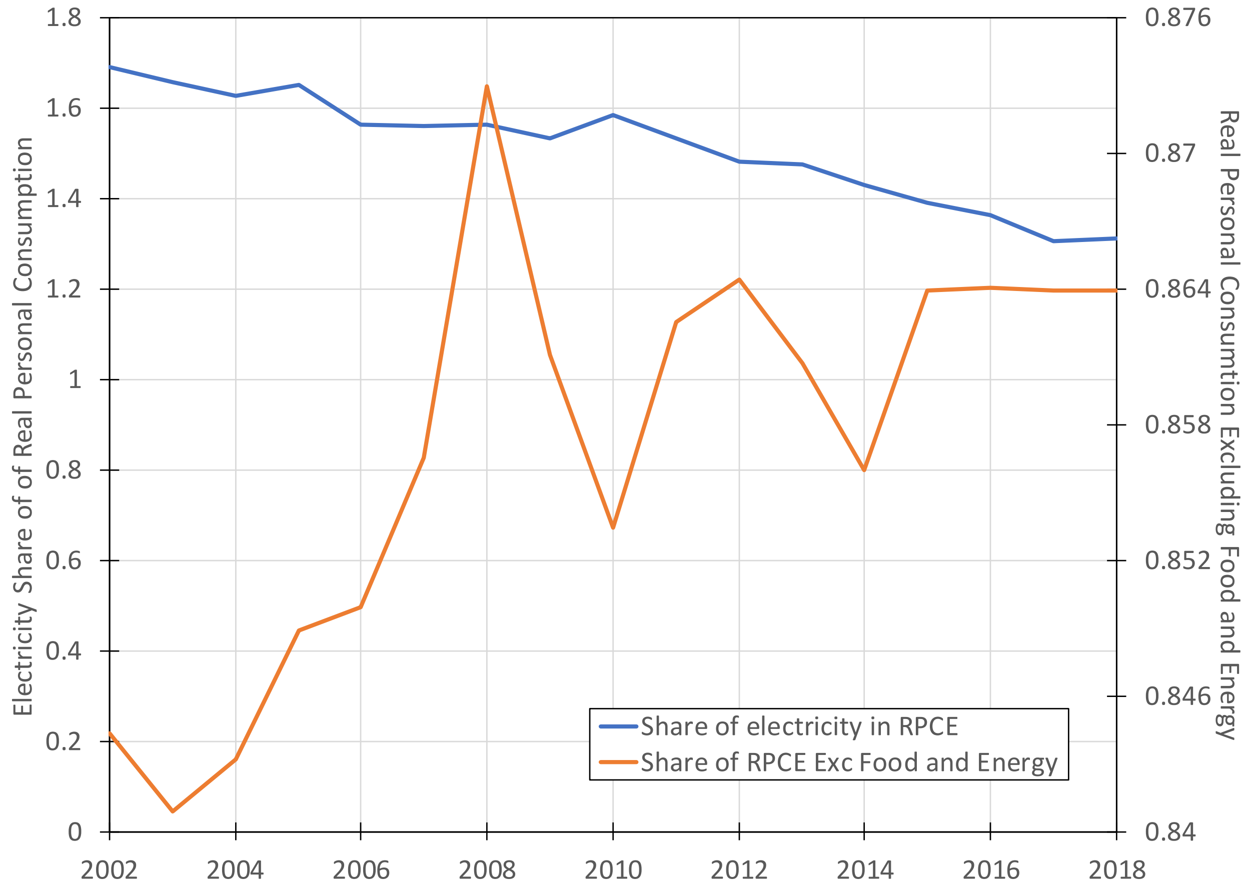

Figure 4.2. Shares of Expenditure on Electricity and All Expenditure excluding Food and Energy in Real Personal Consumption Expenditure

The second indicator is given by the blue line in the figure and is an index value representing the year-to-year change in total household expenditures on electricity relative to BEA's base year of 2009. This indicator suggests that expenditures for electricity continue to grow, relative to previous years and net of inflation effects. This would be expected as the number of residential electricity customers grows in pace with population growth. It does not indicate that electricity is becoming less affordable.

The third macro indicator is given by the red line in the figure and is an index value that normalizes the total expenditures on electricity by the number of US households relative to the BEA base year of 2009. This indicator suggests that relative to previous years, per household expenditures on electricity are declining slightly over time. Of the indicators presented, this index comes closest to suggesting a trend in electricity affordability.

National level macroeconomic data series have value as indicators of electricity affordability in a very general sense, but also have limitations. While trends can be identified, it is much more difficult to assign specific attribution to those trends. For example, we can observe improved electricity affordability at the macro level, but without substantial statistical research, it is difficult to quantify the root causes. As grid modernization activities increase in pace over the coming years, it will be difficult to determine their relative impact on macro affordability compared to the many other actions occurring simultaneously in electricity markets (e.g. fuel price changes, conservation and efficiency activities, emergence of new generation or storage technologies, etc.). However, to the degree that customer costs and benefits derived from grid modernization can be valued, the effect on general electricity affordability will be easier to quantify.

4.5 Emerging Residential Sector Metrics

Emerging metrics address electricity affordability from the perspective of the *cost burden* faced by customers. Cost-burden measures the proportion of income or revenue required to acquire the desired level of electricity service. Customer cost burden is compared to some expected normal or expected burden for a specific geographic area of interest (service territory, state, balancing area, interconnect, etc.). The metrics discussed derive from cost burden. They are much less widely adopted than the long-established and widely understood metrics discussed above, which deal with cost-effectiveness, rather than cost burden.

The DOE multi-year program plan for grid modernization (DOE 2015) established the basis for developing these emerging metrics in addition to cost-effectiveness metrics. In the grid modernization context, affordable electricity "maintains reasonable costs to consumers." The program plan also recommends developing capabilities to "rapidly evaluate new business models and impacts of policy decisions working with states." This guidance is consistent with explicitly accounting for the "ability of users to pay" as defined by Taft and Becker-Dippmann (2014).

When discussing cost burden or customer costs within the metrics framework, we are referring to *net* costs. Implicit in the notion of customer costs of electric service are any offsetting tangible benefits accrued, in addition to the electric service provided. For example, consumers with appliances outfitted to provide demand response service to the utility may receive credits on their bills which may partially offset the cost of their electricity use. As grid modernization proceeds, additional consumer benefits are likely to emerge and provide offsets to the cost of electricity for consumers. Customer affordability metrics need to reflect the net cost of electricity service, including any credits the customer receives.

4.5.1 Customer Cost Burden

Emerging affordability metrics all derive from the notion of customer cost burden. Actions taken to modernize the grid might include the development and deployment of new technologies, new policies, and the creation of new markets for new products and services. These actions require investments and expenditures by electricity providers. The costs to provide these new products and services must be recouped, which generally occurs by passing them on to customers in the form of electricity rates. The aggregation of a customer's net expenditure on electricity over a year relative to that customer's household income (residential) or gross revenue (commercial and industrial) is the cost burden:

$$\text{Household electricity burden} = \frac{\text{Annual residence net electricity bill}}{\text{Annual household income}}$$

$$\text{Business electricity burden} = \frac{\text{Annual enterpise net electricity bill}}{\text{Annual gross revenue}}$$

Customer net expenditures account for subsidies, rebates, and discounts received to reflect the actual out-of-pocket expenditure for electricity. For residential customers, household income is used for convenience, consistency, and availability, but any income metric (e.g., family income, disposable income) can be used as long as it is applied consistently and compared with like metrics. However, for general comparability to other studies, household income is generally preferred. For commercial and industrial customers (businesses), annual gross revenue is used to provide a generally consistent income metric.

Most of the affordability literature focuses on *energy* affordability (all fuels), as opposed to electricity-only affordability. In this volume, we cover *electricity* affordability only and adapt the cost-burden metrics developed in the wider literature for electricity-specific use. In addition, this Reference Document focuses only on the residential sector. The development of meaningful cost-burden metrics for the commercial and industrial sectors may proceed in the future.

4.5.1.1 Affordable Cost Burden

The question of what cost burden is "affordable" is the subject of considerable literature. Existing applications of the affordability metric suggest that residential *energy* bills (including electricity and heating fuel) are affordable if they are no greater than 6 percent of household income (Colton 2011). This threshold is derived by logical deduction, rather than by quantitative analysis, but has been deemed reasonable by many practitioners. The notion Colton (2011) reviews is that many studies have identified that total housing costs should not exceed 30 percent of household income to be affordable, and this is now universally accepted, as evidenced by wide adoption in the mortgage finance industry. Further, utility costs should not exceed 20 percent of total housing costs to be affordable. Therefore, 20 percent of 30 percent equals the 6 percent figure deemed to be the affordable burden for household utility costs (Colton 2011). Electricity is not explicitly broken out in this construct, but to estimate the affordable electricity cost burden, the electricity fraction of all utility expenditures is needed. Thus, if electricity costs represent half of the energy costs of the household, the affordable electricity burden would be 3 percent.

Other practitioners use other approaches for determining the affordable cost burden threshold. The ACEEE examined metropolitan area Census data using the American Housing Survey and the American Community Survey (ACS) (Drehobl and Ross 2016) and found median income households had a median energy burden of 3.5 percent, while the median low-income burden was 7.2 percent, and higher-income households had a median energy burden of 2.3 percent. Drehobl and Ross (2016) identify several possible cut-off points for what defines affordable:

- Six percent derived originally from Colton (2011), which is based on the 30 percent of income cap for housing costs and 20 percent of shelter costs for energy.
- The Applied Public Policy Research Institute for Study and Evaluation models severe shelter burden as 50 percent of income and energy costs as about 22 percent of shelter costs, or 11 percent of income.
- The Nevada threshold is that low-income home energy burdens should be no higher than the median.
- Others point to a level no more than twice the median.

For ACEEE's purposes, Drehobl and Ross settled on the median burden metric for their examination of metropolitan area energy affordability for low-income customers (Drehobl and Ross 2016). This metric suggests that the affordable energy burden would be no higher than the median energy burden for the geography being analyzed.

European researchers suggest other alternative energy affordability threshold metrics (Heindl and Schuessler 2015):

- The Ten Percent Rule defines a household as fuel poor if it uses 10 percent or more of disposable income for energy services (used in the United Kingdom since 1991).

- Low-Income/High Cost is when expenditures on all energy services are above the median expenditure and the household falls below the official income poverty line after expenditure on all energy services.
- Twice the median burden defines a household as energy poor if their total energy expenditure is 2 times the median of the overall population. This metric offers a couple of advantages in that it is not a static value and it is not specifically linked to low income, although in practice it likely is.

For the purposes of evaluating GMLC outcomes, a broadly applicable standard threshold is attractive. Based on the evolution of the general housing cost affordability threshold of 30 percent, experience has shown that metric to have gained practically universal acceptance as a guiding criterion in mortgage finance, low-income housing assistance, and other forms of household financial assistance programs and policies. It would not seem unreasonable to derive a residential electricity affordability threshold standard from the housing cost affordability threshold standard.

Such a standard does not explicitly require the identification of low-income households but applies generally to all households. However, as will be discussed, derivative headcount metrics necessarily require stratification of households by income classes. Using a flat percentage threshold provides a simple demonstration of the application of the affordability metrics. It also allows for analytical flexibility because metrics can be estimated for various threshold values to illustrate threshold sensitivity. The metrics examined for GMLC purposes were estimated using alternative fixed-percentage threshold values.

4.5.2 Electricity Affordability Gap

The first metric deriving from the calculation of the household electricity cost burden is the electricity affordability gap. The electricity affordability gap is the ratio of the dollar amount by which electricity bills in a specified geographic region vary from what electricity bills would be if they were set equal to an affordable percentage of income. This factor is simply the ratio of the household electricity burden to the affordable threshold burden deemed to apply to that household:

$$\text{Household electricity affordability gap} = \frac{\text{Household electricity cost burden}}{\text{Affordable cost burden threshold}}$$

This metric gives an indication of how much actual electricity costs vary from the threshold burden deemed to be affordable. For example, if the affordable electricity burden deemed to apply to a service territory is 4 percent and the customer cost burden is 6 percent, the gap is calculated as follows:

$$\frac{6\%}{4\%} = 1.5,$$

indicating that customers incurred net electricity costs that were 1.5 times greater than what would have been affordable. This metric provides insights into the *current* state of electricity affordability.

4.5.3 Electricity Affordability Gap Index

The affordability gap index simply tracks the electricity affordability gap ratio for a specific geography through time (t+y (y = years)), relative to a base year:

$$\text{Household electricity affordability gap index} = \frac{\text{Affordability gap}_{(t+y)}}{\text{Affordability gap}_{(t)}}$$

For example, if the affordability gap metric is 1.5 in the base year and increases to 1.8 in the analysis year, the affordability gap index is calculated as follows:

$$\frac{1.8}{1.5} = 1.2,$$

indicating that the affordability gap has widened by a factor of 1.2 over the analysis period. This metric provides insights into the *trend* in electricity affordability.

4.5.4 Electricity Affordability Headcount

A headcount metric equates the electricity burden and related affordability gap to the number of affected households. The number or percentage of households facing electricity costs above the affordable threshold is estimated based on the household electricity burden explained above for specific geographic coverages. For the case where customer billing data have been matched with customer household income data, the headcount is simply the summation of the households that have an electricity affordability gap greater than 1.

In cases where public data are necessary to estimate the electricity affordability gap, the analysis is more complex and requires the use of Census ACS data on household income to do the estimation. The ACS data are used to derive income bins for the households in the affected geography. Specifically, using the Census web form interface, the analyst acquires, for the subject geography, the ACS 5-year data for Table B19001 (Census 2018) on household income, which bins the number of households into 16 discrete annual income bins. This provides the highest income resolution possible for calculating average burdens using public data.

Next, for each income bin, the midpoint income is calculated. This will be the value used for the income portion of the burden calculation. For the endpoints of the income distribution, judgment is required. For simplicity, it may be acceptable to use the bounding values of the end-point bins (e.g., the maximum value of the lowest bin and the minimum value of the highest bin). This will slightly distort the end-point burden calculations. However, under common affordability threshold burden values, it would be expected that the lowest bin would always exceed the affordable cost burden threshold and the highest bin would never exceed the affordable cost burden threshold.

Next, each income bin's share of households is calculated by dividing each bin's number of households by the total number of households. The cost burden by income bin is calculated by dividing the estimated average customer cost for the area of interest by each income bin midpoint income. This yields 16 individual customer cost-burden values, one for each segment of the household income distribution. Taking the weighted average of the 16 values yields the area average customer cost burden. Using the midpoint of each bin implicitly assumes that the number of households in each income bin is normally or uniformly distributed within the income bin such that the midpoint income would represent the average of the bin.

With the cost burden by income bin calculated, the number of households facing electricity cost burdens above the affordable threshold can be estimated by varying the threshold percentage deemed to be affordable. This is done by summing the bins of all cost burdens greater than the threshold value. This value is reported as the percentage of all households in the analysis area facing electricity net costs above the affordable threshold.

4.5.5 Electricity Affordability Headcount Index

The affordability headcount is calculated for a series of years. The index simply tracks this value for a specific geography through time (t+y (y = years)), relative to a base year:

Household electricity affordability headcount index =

$$\frac{\%\text{ Households above the affordable threshold}_{(t+y)}}{\%\text{ Households above the affordable threshold}_{(t)}}$$

For example, given our example territory, the number of households estimated to have electricity costs higher than the established affordable threshold is 10,000 of 100,000 (10 percent) in the base or reference year. In the analysis year, this number is estimated to be 15,000 of 120,000 (12.5 percent). The headcount index would be calculated as follows:

$$\frac{12.5\%}{10.0\%} = 1.25,$$

suggesting that the number of households facing electricity costs above the affordable threshold rose 25% between the base year and the analysis year.

4.5.6 Average Customer Electricity Cost

Stakeholder input suggests that average electricity costs (effective rates) by customer class would provide an additional meaningful affordability metric. As rates change, electricity costs and related cost burdens also change. Grid modernization activities that result in rate changes ultimately can be linked to changes in customer affordability.

Average rates alone are not a satisfactory indicator of whether the cost of electricity is affordable. There must be some comparison to average usage of electricity to estimate actual affordability. For example, most of the southern states had average residential rates lower than the national average, but also had monthly electricity costs that were generally higher than the national average. This suggests that electricity is the principal fuel used in these states and usage was much higher than the national average.

The monthly average customer cost or effective rate ($/kWh) for a given geographic coverage *i* and customer class *c* is indicated by the following simple equation:

$$\text{Monthly Average Customer Cost}_{(i,c)} = \frac{\text{Total Revenue}_{(i,c)}}{\text{Total Consumption}_{(i,c)}}$$

4.5.7 Average Customer Electricity Cost Index

Tracking this effective rate through time results in an index for making relative comparisons between time periods:

$$\text{Average Customer Cost Index} = \frac{\text{Avg Customer Cost}_{(t+y)}}{\text{Avg Customer Cost}_{(t)}}$$

4.5.8 Maturity Level

These measures are generally understood and are reflected in the literature for the residential sector. In addition, forms of cost-burden metrics are used for determining eligibility for participation in utility or government low-income programs such as weatherization assistance, bill assistance, etc. Very little has been done to analyze commercial and industrial customer affordability using the cost-burden metric approach. Compared to the cost-effectiveness metrics discussed in Section 4.2, the maturity of these metrics is low. There are applications in the literature, but industry-standard approaches for their use, especially for assessing the impacts of grid modernization, have yet to be developed.

4.5.9 Applications

The existing metrics described in Sections 4.2 and 4.3 are used widely within the context of grid investments and are generally understood to be industry-standard approaches for measuring costs and benefits. Voluminous literature exists that both derives and documents the theory and application of cost-effectiveness metrics. National assessments, state PUC regulatory processes, and firm-level investment decisions all rely on the established cost-effectiveness metrics.

The emerging cost-burden metrics are of value primarily to electricity regulators such as PUCs and state or municipal agencies charged with caring for the interests of electricity customers. Having a consistent methodology for examining potential changes in the affordability of electric service induced by future grid modernization and the development of new products and services provides a customer-side check on the impacts of modernization. Beyond grid modernization, reliable and consistent affordability metrics can provide quantitative standardization for how cost equity concerns are analyzed.

4.5.10 Data Source and Availability

As with all metrics, affordability metrics are only as valuable as the quality of the data used to derive them. Fundamentally, two data sources are required to estimate electricity cost burden: household electricity cost and household income. Ideally, the most robust estimation of cost burden would be made using individual customer annual billing data (net bill) and individual customer annual household income. While electricity utilities would have the billing data for their customers, they may or may not also have customer household income data. Entities other than the electricity service provider are not likely to have customer billing data or customer income data. The methodology described details how metrics can be estimated with or without access to these key data sets. Public data sources are used to demonstrate the application with the understanding that the availability of specific customer-level data would be the preferred case for deriving the most meaning from the metrics.

The firm Fisher, Sheehan, and Colton (2013) has expanded on the notion of the 6 percent affordability threshold and now provides a public, nationwide, data set on home *energy* affordability derived from using county-level household income and a proprietary model for estimating annual average customer electricity bills using the Residential Energy Consumption Survey (RECS) microdata, ACS data, and public weather data on heating and cooling degree-days by region. The firm publishes the data annually for each state and its counties, segmented by income bins.

In the absence of utility-supplied customer billing data, there are public sources of summarized residential billing data. The EIA provides annual and monthly summarization of electricity sales and revenue by customer class for all utilities in the country that file Form 861 (EIA 2018). Service territory average electricity bills can be simply calculated by dividing reported residential electricity sales revenue by the number of customers reported. This provides a relatively geographically refined estimate of household electricity cost but sacrifices the potential refinement that may be possible using the RECS microdata to account for household size, weather, and other factors. However, using the EIA Form 861 data requires much less analysis time than performing econometric analysis of the RECS data. The use-case discussion will examine these tradeoffs. For the purposes of summarizing average customer costs per kilowatt-hour, the Form 861 data, adjusted for inflation, would be sufficient to generate effective average rate estimates at the national, state, and service area geographic levels.

4.5.11 Challenges

Research is needed to develop an approach for constructing such metrics for nonresidential customer classes. In addition, these metrics would be used by entities that can hypothesize the impact of cost and benefit allocations on customer classes (e.g., rate making). Research is needed to understand the trade-off between analytical convenience and accuracy of metric calculations.

4.5.11.1 Commercial and Industrial Sector Metrics

Little if any research has been done to estimate empirically what constitutes affordable electricity to businesses. Unlike the residential sector, there is no convergence around a threshold gross revenue percentage deemed to indicate an affordability bound. While residences are somewhat homogeneous, businesses vary widely in their use of electricity relative to their gross revenues. Electricity-intensive industries necessarily spend higher proportions of their input budgets on electricity, while for other businesses, electricity use can be minor, relative to all other production inputs. Section 4.6 proposes a methodology for addressing affordability for commercial and industrial customers.

4.5.11.2 Affordability Impact Assessment

Performing impact analysis using these emerging metrics will depend upon reliable assignment of costs and benefits to rates, exogenous to the impact analysis. The emerging metrics discussed in this section provide lagging measures of general electricity affordability. The next step is to link the metrics to the output of cost allocation analysis. To estimate the affordability impacts of future grid modernization will require the translation of expected activities into costs and benefits, then allocation of costs and benefits to annual customer costs. This can require complex modeling, depending on the actions hypothesized. For example, new service pricing may induce offsetting behavior among customers. It will be increasingly important to reliably allocate the benefits of customer actions under a modernized grid as credits against annual net electricity costs (net bill).

4.5.11.3 Use of Average Annual Bill Data

As discussed, in the absence of utility customer- or residence-specific billing data for the numerator of the cost-burden metric, average household bills can be estimated from public data sources. At least two concerns should be further studied. First, those having lower household income would be expected to have received higher proportions of subsidies. For example, most utilities have some form of low-income utility assistance and/or “lifeline” type of service for the lowest income customers. This noticeably reduces the cost burden faced by these customers, making the use of a class or geographic average less representative or misleading. The Alaska use case discussed in Section 4.8 is valuable because the customer cost data provided explicitly netted out the effect of customer subsidies. Second, the use of average annual net bills implies that a "top-down" average cost burden would not differ significantly, in aggregate, from a cost burden carefully derived from data on household size, electricity proportion of fuels used, heating and cooling degree-days, electric load profiles, floor space, or other explanatory variables. A useful test would be to estimate and compare the affordability metrics using alternative formulations of the net electricity cost derived from public data sources including RECS, EIA Form 861, or available state-level data sources.

Examining customer affordability using annual average bills can mask acute affordability challenges that could be revealed using monthly billing data. Some households, which would appear to face affordable electricity when costs are figured on an annual basis, may face bills that exceed affordability thresholds during certain months of high heating or cooling demand. Accounting for this potential would add customers to the headcount metrics and require that billing data partners supply monthly data. EIA data from Form-861M (EIA 2018) could provide a useful test for identifying the impact of examining monthly versus annual customer cost data. In subsequent sections, EIA's Form-861M monthly data are used to provide examples of the metrics.

4.6 Proposed Commercial and Industrial Affordability Metrics

A lot of effort has been devoted to developing electricity affordability metrics for different sectors and for the benefit of consumers, but no attempts have been made to look at the problem from the producer's perspective. This study is the first of its kind that tries to quantify the notion of affordability from the producer's perspective. Starting with the marginal principle or the cardinal rule of profit maximization, and relying on publicly available databases, this study presents a simple approach to understanding electricity affordability from the perspective of the producer.

The concept of affordability when approached from the perspective of the firm as opposed to the consumer poses a different kind of challenge and as such a generalized metric to quantify it comes with its own set of challenges/limitations. Though both agents are price takers, a firm's concern is one of profitability, rather than electricity affordability. And, while the former can be used to make inferences about the latter, the firm has the power of technology at its disposal which can be used to reverse a potentially unprofitable situation implied by electricity costs above the affordable threshold. This implies that a generalized metric for all sectors or even for all firms within the same sector is not feasible.

4.6.1 Methodology

The objective of this exercise was to show (using publicly available data) that though manufacturers have facilities in different states and across different counties within the same state, not all these facilities are profitable in so far as input (electricity) use is concerned. In other words, electricity is not affordable across all these facilities.

More formally, not all these facilities display the profit maximizing rule that calls for an equality between the marginal benefit from an additional unit of input (electricity) use and the marginal cost of an additional unit of input (electricity) use.

The IMPLAN (Economic Impact Analysis for Planning) database provides electricity use (in dollar terms) by each sector and the accompanying output for each sector 'q'. Data on the use of electricity 'e' (in MWh) by sector was obtained from EIA. These numbers allow us to compute the average productivity (output per MWh) values and this is the starting point of this analysis. Using the marginal principle and these average productivity ($AP_E = \frac{q}{e}$) values, the Marginal Productivity of one MWh of electricity was computed as follows:

Taking partial derivates of $AP_E = \frac{q}{e}$,

$$\frac{\delta AP_e}{\delta e} = \frac{e}{e^2}\frac{\delta q}{\delta e} - \frac{q}{e^2}$$
$$\Rightarrow \frac{\delta AP_e}{\delta e} = \frac{1}{e}\left\{\frac{\delta q}{\delta e} - \frac{q}{e}\right\}$$
$$\Rightarrow \frac{\delta AP_e}{\delta e} = \frac{1}{e}\{MP_e - AP_e\}$$
$$\Rightarrow MP_e = \left\{\frac{\delta AP_e}{\delta e}\right\} * e + AP_e$$

Further, the Marginal Revenue Product of Electricity or the MRP_e is defined as follows: $MRP_e = MR * MP_e$. The Marginal Revenue Product of Electricity is what a unit of electricity will earn (revenue wise) irrespective of location, or it is the marginal benefit from an additional unit of electricity. More formally,

Marginal Product: If electricity use increases by 1 MWh, what is the corresponding increase in output?

Marginal Revenue: As output increases by 1 unit, what is the increase in revenue?

Marginal Revenue Product: As electricity use increases by 1 MWh, what is the corresponding increase in revenue?

When contrasted with the price of 1 MWh of electricity, this allows one to examine if electricity's contribution towards revenue exceeds its cost or vice versa. This comparison allows for the design of a simple metric that shows us when electricity is above or below the affordable threshold.

4.6.1.1 Electricity Affordability by State by Industry

The starting point of this analysis was the industry aggregates obtained from the IMPLAN database and electricity use (in MWh) from the EIA. Thereafter, a fraction (y/x) was created to determine each state's contribution to this national output and consumption of electricity. In other words, we started with the numeric $\frac{yQ}{xE}$, where y and x were defined as follows:

$$y = \frac{state\ GDP\ in\ the\ sector}{national\ GDP\ in\ the\ sector} * (industry\ output\ in\ that\ sector)$$

$$x = \frac{state\ GDP\ in\ the\ sector}{national\ GDP\ in\ the\ sector} * \left\{\frac{industry\ output\ in\ the\ sector}{total\ industrial\ output}\right\} * \{Total\ electricity\ use\ by\ the\ industrial\ sector\}$$

This yields the AP_E values for 2016 and 2014 for each of these states and these are then used to compute MP_E (marginal product of a unit of electricity). For the state level analysis, the Marginal Revenue was computed as the change in GDP in the focus sector in the state (adjusted for inflation). This allows us to compute the MRP_e which is then compared with the retail electricity prices for the industrial sector[20] by state to infer affordability. In the absence of information on the state level production functions, the

[20] Source: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a

industry level production functions were adapted (using suitable weights) to arrive at the state level numbers.

Further, electricity is a complement in production. This essentially means that the contribution of electricity to output (at the margin) also depends on the other inputs that are employed along with it. Mathematically, this means that the cross partial effect of other inputs 'i' on the marginal productivity of electricity is positive.

Mathematically, what this means is that:

$$Marginal\ Product\ of\ Electricity = MP_e(i) = \frac{\delta Q(i)}{\delta E} \tag{1}$$

$$\Rightarrow \frac{\delta MP_e}{\delta i} = \frac{\delta^2 Q(i)}{\delta E\ \delta i} > 0, \forall i \tag{2}$$

Equation 2 above captures the cross partial effect of other inputs on the marginal productivity of a unit of electricity and because electricity is a complement (to the other inputs) in production, its productivity is affected by the presence of other inputs.

To control for this cross partial effect, i.e. to isolate the contribution of *just* electricity to the total output, electricity's weight in the total value of inputs was used. So, if VA_i represents the value added by each input 'I' in the auto industry, the contribution of electricity to total output (in value terms) was weighted by the following number:

$$\frac{VA_E}{\Sigma_{i=1}^{\mathrm{N}} VA_i} \tag{3}$$

4.6.1.2 Electricity Affordability by State by Industry by Firm

The starting point of this analysis is once again the national-average productivity numbers from the IMPLAN database, the firm level numbers from their annual reports, the electricity use (in MWh) by industry. These numbers are then suitably adjusted to capture the facility level metrics. Specifically, y is the share of output produced in each facility relative to the national output. The employment intensity of the firm's facility was used to compute the facility's share of output in total firm production. x was constructed to capture the electricity intensity of each of these facilities, or the expenditure on electricity by each of these facilities. The facility size in square footage relative to the total area under manufacturing by the firm times the market share of the firm in US sales[21] was used to determine the electricity use intensity of the facility. More formally, these are defined as follows:

[21] Source: https://www.statista.com/statistics/239614/vehicle-sales-market-share-of-ford-in-the-united-states/
Source: https://www.statista.com/statistics/239607/vehicle-sales-market-share-of-general-motors-in-the-united-states/

$$y = \frac{firm\ size\ (square\ foot)}{total\ area\ under\ manufacturing\ by\ that\ firm\ in\ the\ USA}(market\ share\ of\ firm\ in\ sales\ in\ North\ America) * (number\ of\ cars\ produced\ in\ that\ year)$$

$$x = \frac{employment\ in\ that\ facility}{firm's\ employment\ in\ the\ country}(market\ share\ of\ firm\ in\ sales\ in\ North\ America)* \left\{\frac{industry\ output\ in\ the\ sector}{total\ industrial\ output}\right\} * \{Total\ electricity\ use\ by\ the\ industrial\ sector\}$$

The Marginal Revenue numbers for each facility were computed based on the facility's size relative to the firm's overall facility size in the nation. An approach similar to the one used in the calculations of Marginal Product were used to compute the Marginal Revenue numbers.

More formally, the following approach was used to arrive at the firm level values (Marginal Revenue):

$$AR = \frac{TR}{Q},$$
$$\frac{\delta AR}{\delta Q} = \frac{Q}{Q^2}\frac{\delta TR}{\delta Q} - \frac{TR}{Q^2}$$
$$\Rightarrow \frac{\delta AR}{\delta Q} = \frac{1}{Q}\left\{\frac{\delta TR}{\delta Q} - \frac{TR}{Q}\right\}$$
$$\Rightarrow \frac{\delta AR}{\delta Q} = \frac{1}{Q}\{MR - AR\}$$

where Q is the number of cars produced by each of the facilities and this number was arrived at as follows:

$$\left(\frac{factory\ floor\ space}{total\ floor\ space\ used\ in\ production}\right) * (market\ share\ in\ vehicle\ sales\ for\ that\ year\ in\ North\ America) * (number\ of\ cars\ sold\ that\ year\ by\ the\ firm\ in\ the\ North\ America^{22})$$

The revenue contribution of each facility was determined by the share of cars produced by the facility (as obtained in the above step) times the sales revenue for that year in the automotive segment in North America. The resulting marginal revenue numbers were then combined with the marginal product numbers to arrive at the estimates of marginal revenue product or marginal benefit of a unit of electricity.

The resulting Marginal Revenue Product (Marginal Benefit) numbers were compared with the average (monthly) electricity prices for each county where these facilities are located, and inferences drawn whether electricity is affordable or not in the facility under consideration.

At the firm level too, since the exact form of the production function in each of the firm's manufacturing facilities was not known, the industry level weights (to isolate just the contribution of electricity) were used in the firm level analysis.

Further, to demonstrate the temporal nature of the concept of affordability, a single facility over a period of a year was studied.

[22] source: http://www.goodcarbadcar.net/2012/10/ford-motor-company-sales-figures/
http://gmauthority.com/blog/gm/general-motors-sales-numbers/

To demonstrate the effectiveness of this metric to capture the notion of affordability, the automobile industry (specific firms chosen for purpose of this analysis were GM and Ford) was selected, and the suggested affordability analysis carried out.

All the data used in this analysis has been sourced from publicly available databases. BEA, BLS, EIA, the FRED database (FRED 2018) and annual reports for the firms under study were utilized. All measures were adjusted where required to be expressed in the same dollar value across the board.

4.6.2 Example Industrial Sector Results

The results from the analysis can be summarized as follows. A visual comparison of the marginal benefits from one MWH of electricity with the cost of that MWh allows us to infer whether a specific location provides electricity that is affordable. Tables 4.3 and 4.4 summarize state-level results for the automotive manufacturing and food service industries. Tables 4.5 and 4.6 summarize selected plant-level results for General Motors and Ford Motor Company.

Table 4.3. Industry-Specific – State Specific Affordability Results for the Automotive Industry (2017$)

State	Annualized Marginal Benefit of Electricity ($/MWH)	Retail Industrial Price of Electricity ($/MWH)	Electricity Costs within Affordable Threshold
Alabama	91.31	61.64	Yes
Alaska	100.52	155.23	No
Arizona	95.54	61.88	Yes
Arkansas	79.95	61.99	Yes
California	94.55	121.60	No
Colorado	100.29	74.97	Yes
Connecticut	11.09	130.69	No
Delaware	116.27	82.76	Yes
Florida	95.65	78.41	Yes
Georgia	63.20	59.51	Yes
Hawaii	98.32	211.09	No
Idaho	85.68	66.82	Yes
Illinois	54.60	66.36	No
Indiana	92.04	71.13	Yes
Iowa	133.84	61.71	Yes
Kansas	99.16	76.36	Yes
Kentucky	95.84	57.80	Yes
Louisiana	122.60	51.79	Yes
Maine	92.77	91.39	Yes
Maryland	96.56	80.43	Yes

State	Annualized Marginal Benefit of Electricity ($/MWH)	Retail Industrial Price of Electricity ($/MWH)	Electricity Costs within Affordable Threshold
Massachusetts	89.55	136.43	No
Michigan	83.43	70.47	Yes
Minnesota	182.62	75.21	Yes
Mississippi	83.43	59.10	Yes
Missouri	85.86	72.63	Yes
Montana	99.45	51.58	Yes
Nebraska	76.38	78.45	No
Nevada	95.10	59.97	Yes
New Hampshire	87.24	125.85	No
New Jersey	98.09	103.65	No
New Mexico	169.10	59.55	Yes
New York	134.25	61.50	Yes
North Carolina	92.24	64.39	Yes
North Dakota	73.64	81.41	No
Ohio	76.92	71.17	Yes
Oklahoma	98.05	51.20	Yes
Oregon	75.29	61.74	Yes
Pennsylvania	127.51	70.62	Yes
Rhode Island	100.81	137.54	No
South Carolina	91.11	62.12	Yes
South Dakota	85.33	77.23	Yes
Tennessee	88.26	57.95	Yes
Texas	77.81	54.33	Yes
Utah	99.05	64.53	Yes
Vermont	1034.32	104.31	Yes
Virginia	70.24	66.86	Yes
Washington	131.58	45.21	Yes
West Virginia	95.46	67.00	Yes
Wisconsin	-69.64	76.46	No
Wyoming	119.16	70.62	Yes

Table 4.4. Industry-Specific – State Specific Affordability Results for the Food Service Industry (2017$)

State	Annualized Marginal Benefit of a Unit of Electricity ($/MWH)	Retail Commercial Price of Electricity ($/MWH)	Electricity Costs within Affordable Threshold
Alabama	568.08	111.13	Yes
Alaska	539.63	175.55	Yes
Arizona	585.53	104.14	Yes
Arkansas	628.29	82.30	Yes
California	598.93	150.75	Yes
Colorado	592.55	95.98	Yes
Connecticut	574.85	157.50	Yes
Delaware	577.74	100.69	Yes
Florida	582.75	89.02	Yes
Georgia	530.74	98.13	Yes
Hawaii	592.82	246.42	Yes
Idaho	598.73	77.56	Yes
Illinois	567.97	90.18	Yes
Indiana	568.01	100.11	Yes
Iowa	581.93	91.68	Yes
Kansas	565.37	104.72	Yes
Kentucky	578.36	95.71	Yes
Louisiana	576.29	85.95	Yes
Maine	587.54	120.86	Yes
Maryland	582.74	109.94	Yes
Massachusetts	591.71	156.00	Yes
Michigan	584.50	106.36	Yes
Minnesota	587.07	98.58	Yes
Mississippi	584.50	95.74	Yes
Missouri	576.81	92.61	Yes
Montana	580.21	101.92	Yes
Nebraska	577.97	88.00	Yes
Nevada	588.59	79.37	Yes
New Hampshire	594.02	144.33	Yes
New Jersey	569.13	122.60	Yes
New Mexico	569.81	97.48	Yes
New York	582.15	144.50	Yes

State	Annualized Marginal Benefit of a Unit of Electricity ($/MWH)	Retail Commercial Price of Electricity ($/MWH)	Electricity Costs within Affordable Threshold
North Carolina	594.19	86.19	Yes
North Dakota	-919.81	91.48	No
Ohio	570.90	99.74	Yes
Oklahoma	537.05	76.64	Yes
Oregon	602.58	89.09	Yes
Pennsylvania	561.82	92.20	Yes
Rhode Island	582.35	148.77	Yes
South Carolina	577.58	102.77	Yes
South Dakota	585.97	95.85	Yes
Tennessee	597.67	101.92	Yes
Texas	586.86	82.57	Yes
Utah	590.32	87.56	Yes
Vermont	594.67	145.43	Yes
Virginia	583.45	79.33	Yes
Washington	591.69	84.28	Yes
West Virginia	563.34	93.53	Yes
Wisconsin	576.67	107.72	Yes
Wyoming	348.47	94.00	Yes

Table 4.5. Firm-Specific – County Specific Affordability Results for Ford Motor Company (2017$)

City, State, Facility	Zip	County	Service Provider	Annualized Marginal Benefit of a Unit of Electricity ($/MWH)	County Electricity Price ($/MWH)	Electricity Costs within Affordable Threshold
Buffalo, NY (Stamping)	14219	Erie	(1) NY State Elec & Gas Corp (2) Niagara Mohawk Power Corp	-77.35	65.61, 57.79	No
Chicago, IL (Assembly)	60663	Cook	Commonwealth Edison Co	12.97	57.27	No
Chicago, IL (Stamping)	60411	Cook	Commonwealth Edison Co	36.53	57.27	No
Livonia, MI (Transmission)	48150	Wayne	DTE Electric Company	35.20	67.39	No
Sterling Heights, MI (Transmission)	48314	Wayne	DTE Electric Company	23.71	67.39	No
Flat Rock, MI (Assembly)	48134	Wayne	DTE Electric Company	15.70	67.39	No
Dearborn, MI (Assembly)	48120	Wayne	DTE Electric Company	11.52	67.39	No
Wayne, MI (Assembly)	48184	Wayne	DTE Electric Company	26.14	67.39	No
Dearborn, MI (Forging)	48126	Wayne	DTE Electric Company	11.34	67.39	No
Woodhaven, MI (Forging)	48183	Wayne	DTE Electric Company	19.88	67.39	No
Dearborn, MI (Stamping)	48120	Wayne	DTE Electric Company	28.15	67.39	No
Woodhaven, MI (Stamping)	48183	Wayne	DTE Electric Company	118.11	67.39	Yes
Dearborn, MI (Stamping)	48126	Wayne	DTE Electric Company	23.11	67.39	No
Dearborn, MI (Engine)	48120	Wayne	DTE Electric Company	89.97	67.39	Yes

City, State, Facility	Zip	County	Service Provider	Annualized Marginal Benefit of a Unit of Electricity ($/MWH)	County Electricity Price ($/MWH)	Electricity Costs within Affordable Threshold
Ypsilanti, MI (Engine)	48193	Wayne	DTE Electric Company	45.07	67.39	No
Romeo, MI (Engine)	48065	Macomb	DTE Electric Company	58.35	67.39	No
Sterling Heights, MI (Engine)	48130	Washtenaw	(1) DTE Electric Company (2) Consumers Energy Co	23.59	67.31 , 82.012	No
Sharonville, OH (Transmission)	45241	Hamilton	Duke Energy Ohio	26.94	84.47	No
Avon Lake, OH (Assembly)	44012	Lorain	(1) Cleveland Electric Illum Co (2) Ohio Edison Co	41.62	63.28, 91.4914	No
Brook Park, OH (Engine)	44142	Cuyahoga	(1) Cleveland Electric Illum Co (2) Ohio Edison Co	18.91	63.28, 91.4914	No
Lima, OH (Engine)	45801	Allen	Ohio Power Co	35.42	122.84	No
Louisville, KY (Assembly)	40241	Jefferson	Louisville Gas & Elec	13.94	68.29	No
Louisville, KY (Assembly)	40213	Jefferson	Louisville Gas & Elec	12.68	68.29	No
Clay Como, MO (Assembly)	64119	Clay	(1) Kansas City Power and Light Co (2) KCP&L Greater Missouri Operations (3) Union Electric Co	11.96	86.69, 67.42, 68.35	No

Table 4.6. Firm-Specific – County Specific Affordability Results for General Motors (2017$)

City, State, Facility	Zip	County	Service Provider	Annualized Marginal Benefit of a Unit of Electricity ($/MWH)	County Electricity Price ($/MWH)	Electricity Costs within Affordable threshold
Arlington, TX (Assembly)	76010	Tarrant	NA	46.43	52.86	No
Bowling Green, KY (Assembly)	42101	Warren	Warren Rural Elec Coop Corp	140.97	61.96	Yes
Detroit, MI (Assembly)	48211	Wayne	DTE Electric Company	192.04	67.39	Yes
Flint, MI (Assembly)	48551	Genesee	(1) Consumers Energy (2) DTE Electric Company	105.09	82.01, 67.39	Yes
Lansing, MI (Regional Stamping)	48917	Eaton	(1) Consumers Energy (2) City of Lansing (MI)	90.76	82.01, 106.19	Yes
Lansing, MI (Assembly/Stamping)	48933	Ingham	(1) Consumers Energy (2) City of Lansing (MI) (3) DTE Electric Company	132.38	82.01, 106.19,67.39	Yes
Lake Orion, MI (Assembly)	48359	Oakland	(1) Consumers Energy (2) DTE Electric Company	266.36	82.01, 67.39	Yes
Bay City, MI (Propulsion)	48708	Bay	(1) Consumers Energy (2) DTE Electric Company	185.80	82.01, 67.39	Yes
Flint, MI (Propulsion)	48552	Genesee	(1) Consumers Energy (2) DTE Electric Company	104.40	82.01, 67.39	Yes
Romulus, MI (Propulsion)	48174	Wayne	DTE Electric Company	85.69	67.39	Yes

City, State, Facility	Zip	County	Service Provider	Annualized Marginal Benefit of a Unit of Electricity ($/MWH)	County Electricity Price ($/MWH)	Electricity Costs within Affordable threshold
Saginaw, MI (Propulsion)	48601	Saginaw	(1) Consumers Energy (2) DTE Electric Company	288.30	82.01, 67.39	Yes
Warren, MI (Propulsion)	48091	Macomb	DTE Electric Company	714.85	67.39	Yes
Flint, MI (Metal Center)	48550	Genesee	(1) Consumers Energy (2) DTE Electric Company	85.41	82.01, 67.39	Yes
Pontiac, MI (Metal Center)	48340	Oakland	(1) Consumers Energy (2) DTE Electric Company	71.19	82.01, 67.39	Yes
Wyoming, MI (Components Holdings Facility)	49509	Kent	Consumers Energy	57.00	82.01	No
Flint, MI (Tooling Center)	48504	Genesee	(1) Consumers Energy (2) DTE Electric Company	20.10	82.01, 67.39	No
Brownstown Charter Twp, MI (Battery Assembly)	48183	Wayne	DTE Electric Company	115.47	67.39	Yes
Kansas City, KS (Assembly & Stamping)	66115	Wyandotte	(1) City of Kansas City City (2) Kansas City Power and Light Co (3) Westar Energy Inc	62.86	85.48, 98.94, 80.803	Yes

City, State, Facility	Zip	County	Service Provider	Annualized Marginal Benefit of a Unit of Electricity ($/MWH)	County Electricity Price ($/MWH)	Electricity Costs within Affordable threshold
Roanoke, IN (Assembly)	46783	Huntington	(1) Indiana Michigan Power Co (2) Duke Energy Indiana LLC	27.44	63.98, 72.57	No
Bedford, IN (Casting)	47421	Lawrence	Duke Energy Indiana LLC	31.32	72.57	No
Marion, IN (Metal Center)	46952	Grant	(1) Indiana Michigan Power Co (2) Duke Energy Indiana LLC	47.90	63.98, 72.57	No
Kokomo, IN (Components Holdings Facility)	46902	Howard	(1) Indiana Michigan Power Co (2) Duke Energy Indiana LLC	99.19	63.98, 72.57	Yes
Warren, OH (Assembly)	44481	Trumbull	(1) Cleveland Electric Illum Co (2) Ohio Edison Co	107.15	63.28, 91.49	Yes
Defiance, OH (Casting)	43512	Defiance	(1) Ohio Power Co (2) The Toledo Edison Co	80.99	122.84, 88.22	No
Moraine, OH (Propulsion)	45439	Montgomery	(1) Dayton Power and Light (2) Duke Energy Ohio	20.52	119.52, 84.47	No
Toledo, OH (Propulsion)	43612	Lucas	The Toledo Edison Co	32.48	88.82	No

City, State, Facility	Zip	County	Service Provider	Annualized Marginal Benefit of a Unit of Electricity ($/MWH)	County Electricity Price ($/MWH)	Electricity Costs within Affordable threshold
Cleveland, OH (Metal Center)	44130	Cuyahoga	(1) Cleveland Electric Illum Co (2) Ohio Edison Co	47.85	63.28, 91.49	No
Spring Hill, TN (Assembly & Propulsion)	37174	Maury	(1) Duck River Electric (2) Middle Tennessee E M C	52.25	55.09,55.93	No
Wentzville, MO (Assembly)	63385	Saint Charles	(1) Cuivre River Electric Corp (2) Union Electric Company	27.52	72.65, 68.35	No
White Marsh, MD (Propulsion)	21162	Baltimore	Baltimore Gas & Electric	52.45	109.94	No
Buffalo, NY (Propulsion)	14207	Erie	(1) NY State Electric & Gas (2) Niagara Mohawk Power Corp	54.76	65.61, 57.79	No
Lockport, NY (Components Holdings Facility)	14094	Niagara	(1) NY State Electric & Gas (2) Niagara Mohawk Power Corp	52.01	65.61, 57.79	No
Rochester, NY (Components Holdings Facility)	14606	Monroe	(1) Rochester Gas & Electric (2) Niagara Mohawk Power Corp	46.43	109.05, 57.79	No

The tables above compare the cost of one MWh of electricity against its contribution to total revenue over the period of a year both at the state level and at the firm level.

The objective of this analysis was to see not only how affordability differs across states for firms within the same industry but also to show how affordability varies by industry itself. In other words, there are some locations (state-wise) where the estimated metric suggests the industry operated at a loss and some others where it operated at a profit. These conclusions follow from the optimization principle. If MRP_i does not equal MC_i for each input under consideration, then the objective function is not optimized, i.e., the firm is not employing the profit maximizing level of input.

Comparing these state level/industry level results with the firm-specific results across different counties in the same state, allows one to see how the firm performs relative to the performance of the industry. So, while the firms might be operating at a loss in some county in a state (implying electricity costs exceed the affordability threshold), at the level of the industry, i.e. at a higher level of aggregation, the results might in fact be somewhat different (electricity costs will be affordable).

By the same logic if in some counties in a state, some firm operates at a profit (implying electricity is affordable), when the results are aggregated to the level of the industry, i.e., the state level, the industry at the state level may be unprofitable, implying that electricity costs exceed the affordability threshold for profitability. This can be justified on two grounds. First, since the affordability metric is designed using average productivity numbers, some of the firms in a state are likely to be less productive than others, thus putting a downward pressure on the average productivity at the industry level. Second, if the number of low productivity firms outweighs the number of high productivity firms, the average value of productivity at the industry level is likely to be low, thus creating a basis for arriving at a situation where electricity costs exceed the affordability threshold.

Since the state level numbers are industry aggregates, they do not adequately capture the situation at the county level where the different firms have their manufacturing facilities. The county level estimates for the firm may however be compared with the state level estimates to infer how the firm is performing relative to the industry in that state. To illustrate this point, electricity in the automobile industry for the state of Michigan appears to be within the affordability threshold, and yet electricity at some of the Ford and GM factories in the state of Michigan is not affordable. This implies two things. First, one aspect of this metric being "marginal productivity," which captures the state of technology, allows one to compare the state of technology at the industry level for that state with the technology deployed by the individual firms in that state. Second, the state of Michigan is home to many miscellaneous auto manufacturing units with differing levels of productivity which in turn affect the aggregate productivity numbers (which are used to derive the marginal estimates) which are critical to inferring affordability. Moreover, a major limitation of this analysis is the absence of information about the exact nature of the production function both at the state level and at the firm (and therefore county) level. This severely limits our ability to compute the productivity numbers and as such these estimates should only be interpreted as representative and not exact.

The state level numbers capture the relationship at the level of the industry. In other words, the state level numbers capture a certain degree of aggregation while the county level results are highly disaggregated. Under the circumstances, it is possible for the results at the two different levels of aggregation to produce contrarian results. Simply put, looking at the averages will not tell you much about the individual outcomes. What it can tell you, however, is how different sectors across the same state are faring in terms of electricity affordability. Having said that, both of these approaches (state level and county level) need to be taken together for a comprehensive understanding of the concept of electricity affordability for businesses.

4.6.3 Implications for Industrial and Commercial Sector Affordability Metrics

Relatively more effort has been devoted to developing residential sector electricity affordability metrics than for looking at the problem from a commercial or industrial sector customer's perspective. This study is the first of its kind that tries to quantify the notion of affordability from that perspective. Starting with the marginal principle or the cardinal rule of profit maximization, and relying on publicly available databases, this study presents a simple approach to understanding affordability from the perspective of a commercial or industrial sector customer.

A generalized approach as opposed to a firm-by-firm approach would not capture the essence of the problem (quantifying affordability) on two fronts. First, unlike in the case of residential customers, businesses do have a certain level of control on the MRP_E aspect of the equation through choice of production technology. An example to consider in this case would be the case of Buffalo, NY. Both Ford and GM have factories in Buffalo, NY, but while GM finds electricity affordable, Ford does not.

A generalized approach in the context of households is easier to implement since household behavior is (assumed) homogenous across income levels. As such a single approach for each income level can be advocated. Besides, data on households is very well documented and as such there are no data limitations involved in a residential sector analysis.

For industry level analysis—there are two levels of heterogeneity that are involved—one stemming from the industry itself and the other stemming from firms within the same industry (and this comes with its fair share of challenges, especially in the context of data). So, a generalized approach (akin to the one for the residential sector) is not possible in this context. Therefore, an understanding of notion of affordability at the industry level needs to be carried out in two levels. The first would be at the level of the industry and the second at the level of all firms within that industry. While the first layer of analysis is fairly easy to carry out since it relies on the use of economy level data (which is very easy to obtain), the second level of analysis requires firm-specific data and, in the absence of exact estimates, proxies to determine these numbers (which are more often than not, very difficult to come by). An example to illustrate this point would be the calculation of electricity intensity at the firm level, across the different locations. Exact metrics on input use are not available and as such proxies based on the size of the manufacturing facility were used to determine electricity intensity for that location.

In conclusion, an industry-specific affordability metric (that captures behavior at the firm level) can be developed. However, because standardized data sources do not exist, the data analysis requirements are substantial. The approach demonstrated here utilized publicly available data sources to form needed proxy values to enable the analysis. This served to demonstrate the approach, but we acknowledge the need for additional refinement.

4.7 Scope of Applicability

Established and emerging affordability metrics have meaning and applicability at any level of desired spatial or grid-hierarchical aggregation. From DOE's perspective, the value of examining the affordability of grid modernization is that the emerging metrics can be examined at all aggregation levels, using uniform calculation methods. Thus, the outcomes of grid modernization investments can be measured in consistent affordability terms at a national, state, congressional district, county, local, or utility-system level.

Established and emerging affordability metrics are useful at the system level from the perspective of internal service-provider decision-making. Cost-effectiveness metrics are used as a matter of standard practice to evaluate investment decisions regarding new power plants, new efficiency technology deployments, new transmission and distribution equipment upgrades, or distributed generation deployment. Cost-burden metrics will become increasingly important at the system level in the future. As the grid becomes more transactive and customers gain access to services that enable them to customize their participation in electricity markets, the metrics will have greater meaning at smaller geographic and temporal scales.

4.7.1 Utility Level

Established and emerging affordability metrics gain wider usefulness at the utility level. Regulated utilities rely upon cost-effectiveness metrics to build their case to their regulators for cost-of-service recovery from their rate base. Decisions regarding construction of new power plants, new efficiency technology deployments, transmission and distribution equipment upgrades, or distributed generation deployment become subject to robust and public estimates of cost-effectiveness metrics that are reviewed and vetted by regulators, investors, the public, and shareholders. Merchant generators also rely upon traditional cost-effectiveness metrics to make investment decisions regarding potential markets for their power.

Customer cost-burden metrics are gaining in importance to individual utilities from the social responsibility perspective. As grid modernization activities proceed, utilities will increasingly want to be perceived favorably among their peers, to their regulators, and to their customers. As the grid becomes more transactive, customers will increasingly be able to choose their electricity supplier. Affordability metrics derived from customer cost burden may become a differentiator for service providers, in the context of socially responsible electricity delivery. Merchant power providers typically are focused on the provision of wholesale power and would only be concerned with cost-burden metrics to the degree that power retailers pass those concerns on explicitly to wholesale providers.

As shown in Figure 4.3, customer affordability metrics can be illustrated in high spatial detail within a utility service area. In this case, the Baltimore Gas and Electric (BG&E) service territory in Maryland is the only electric utility serving Baltimore City, Baltimore County, and Anne Arundel County (EIA 2018). Census block groups were mapped and shaded according to the proportion of households facing monthly electricity costs above the 3 percent affordability threshold. The block groups are binned into ten ranges of percentages of households having cost burdens greater than 3 percent.

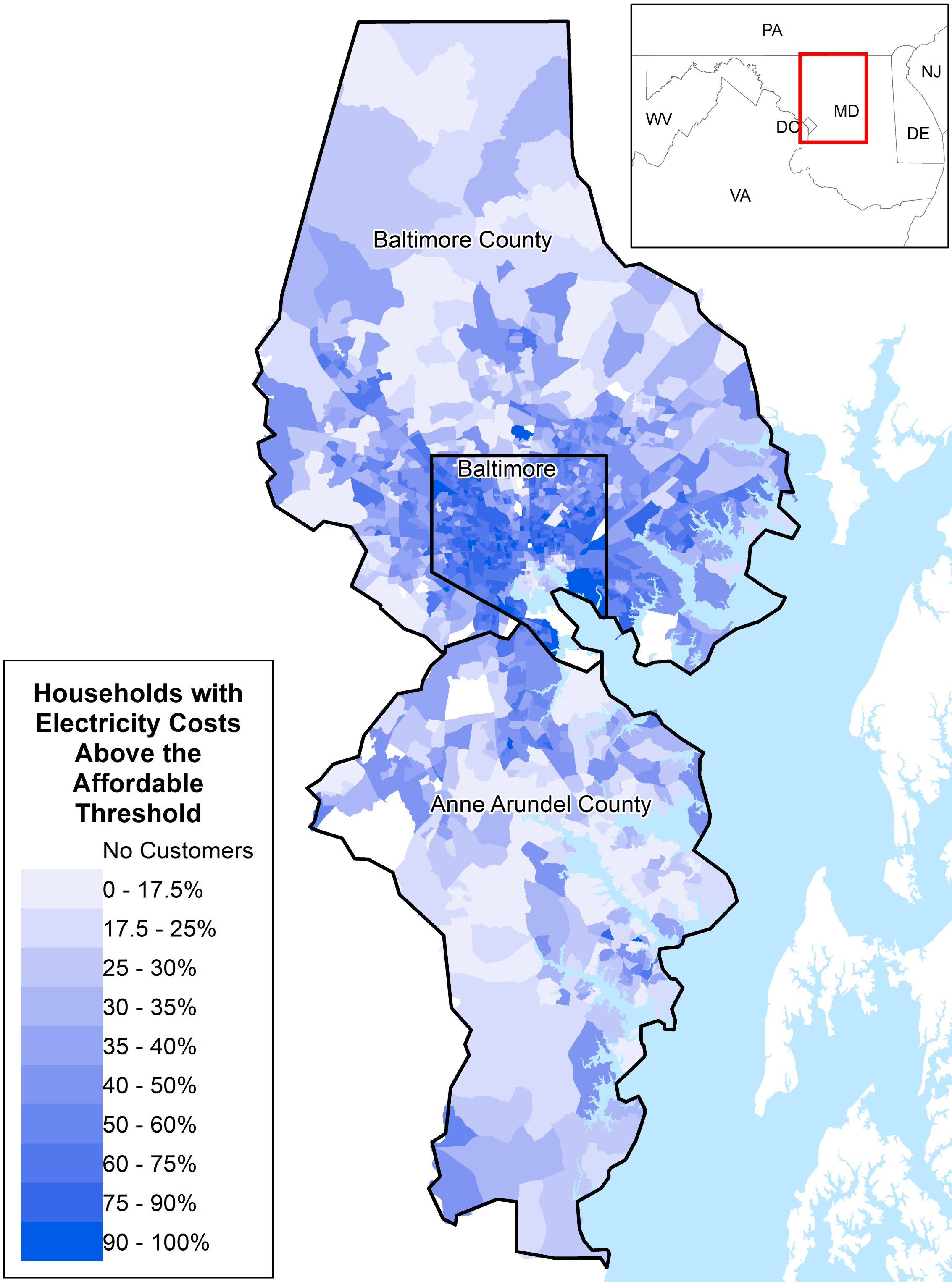

Figure 4.3. February 2017 Residential Customer Affordability (3 percent threshold) by Census Block Group in the Baltimore Gas and Electric Service Area

Two observations from the figure can be made. First, customer affordability varies considerably across spatial extents even within a single county. Electricity is less affordable in low-income areas around the

City of Baltimore, but also in some more rural areas of the county. Suburban areas, where average incomes would be expected to be generally higher, appear to have fewer households with cost burdens greater than the affordable threshold value. Second, even in a geographically small utility service area like BG&E, affordability varies considerably across the territory.

4.7.2 State Level

Established and emerging affordability metrics also have importance at the state level. Most regulated utilities are subject to state regulation. PUCs are generally charged with ensuring that the actions of electricity utilities are fair and equitable toward customers (residents and businesses of the state). Utilities must demonstrate that the costs for which they request recovery from rate payers are fair and equitable. Cost-effectiveness metrics are used as a matter of standard practice to demonstrate the practicality or reasonableness of requested investments.

For the purposes of states and other political jurisdictions, cost-burden metrics are useful in providing an assessment of the equity of proposed rate changes proposed by utilities. Customer advocacy groups could benefit from the availability of uniform affordability metrics applicable at any geographic scale of interest. Adoption of uniform cost-burden metrics would enable utility commissions to consider more formally customer affordability in their deliberations.

Figure 4.4 uses microdata from the most recent RECS (EIA 2013) to illustrate the average customer cost burden across the state groupings used in the RECS. Two observations are possible. The average cost burdens by state are somewhat higher in the South than in other parts of the country, though generally residential electricity rates are lower in that region. This illustrates the effect of average household incomes on the cost-burden metric. Average incomes are generally lower in the southern states than, for example, in the northeastern states. This results in the electricity cost burden being higher. The higher incomes in the northeastern states mitigate the higher electricity costs those customers face, making their cost burden lower.

Figure 4.5 examines the RECS consumer cost and income data in terms of the affordability headcount. Setting the affordable cost burden at 5 percent, the number of households that have cost burdens greater than that threshold value were charted to illustrate the difference among the state groupings used in the RECS. The values range from 7 percent of households in Colorado to over 40 percent of households in Florida, Georgia, North Carolina, and South Carolina, based on the 2009 RECS microdata. The U.S. average for the 5 percent threshold is 27.5 percent of households having cost burdens greater than the threshold value.

As noted in Section 4.5.1.1, these metrics rely upon the selection of a threshold value. Alternative threshold values yield different results. The higher the affordable threshold is set, the higher the number of residential customers that will be estimated to have affordable electricity. The lower the threshold, the higher the number of residential customers that will have electricity cost burdens above the affordable threshold.

The affordability headcount can be illustrated for any level of spatial aggregation (state, county, Census block groups, utility service areas, etc.), as demonstrated above for SMUD in California and below at the county level for the counties in California in Figure 4.6. In this figure, the variation in affordability within the state is evident. Cost burdens were estimated at the utility service area level using the EIA Form 861 data discussed in Section 4.5.8 and the Census ACS data on household income. Observations similar to those derived from the use of the RECS data can be made. Areas with generally higher incomes have fewer households with cost burdens above the affordable threshold (3 percent used in this case). However, counties outside the large investor-owned territories also have higher average electricity costs.

These two factors together suggest the most affordable electricity in California is in the Bay Area counties and central and southern coastal counties.

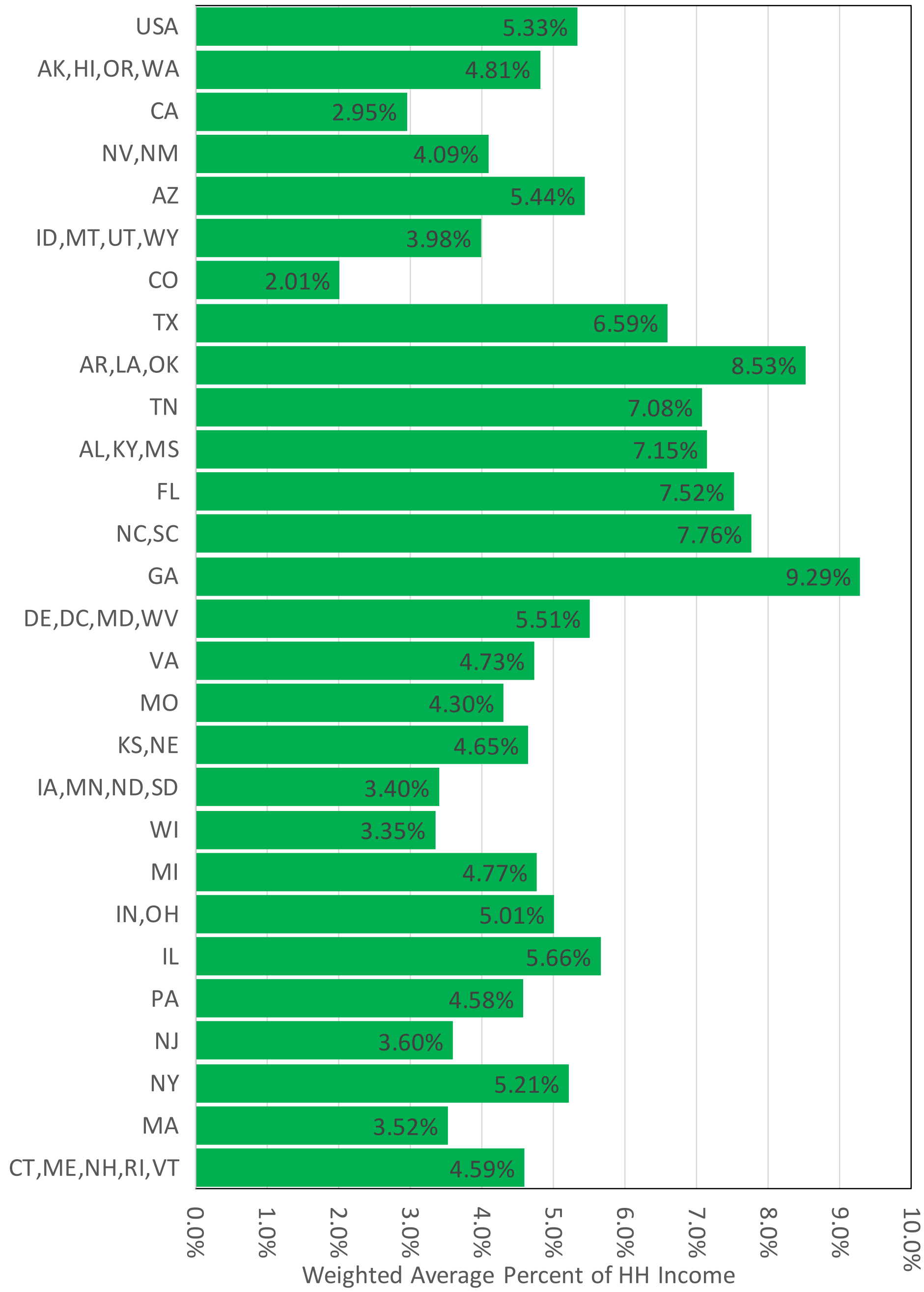

Figure 4.4. 2009 Average Residential Customer Electricity Cost Burden (EIA 2013)

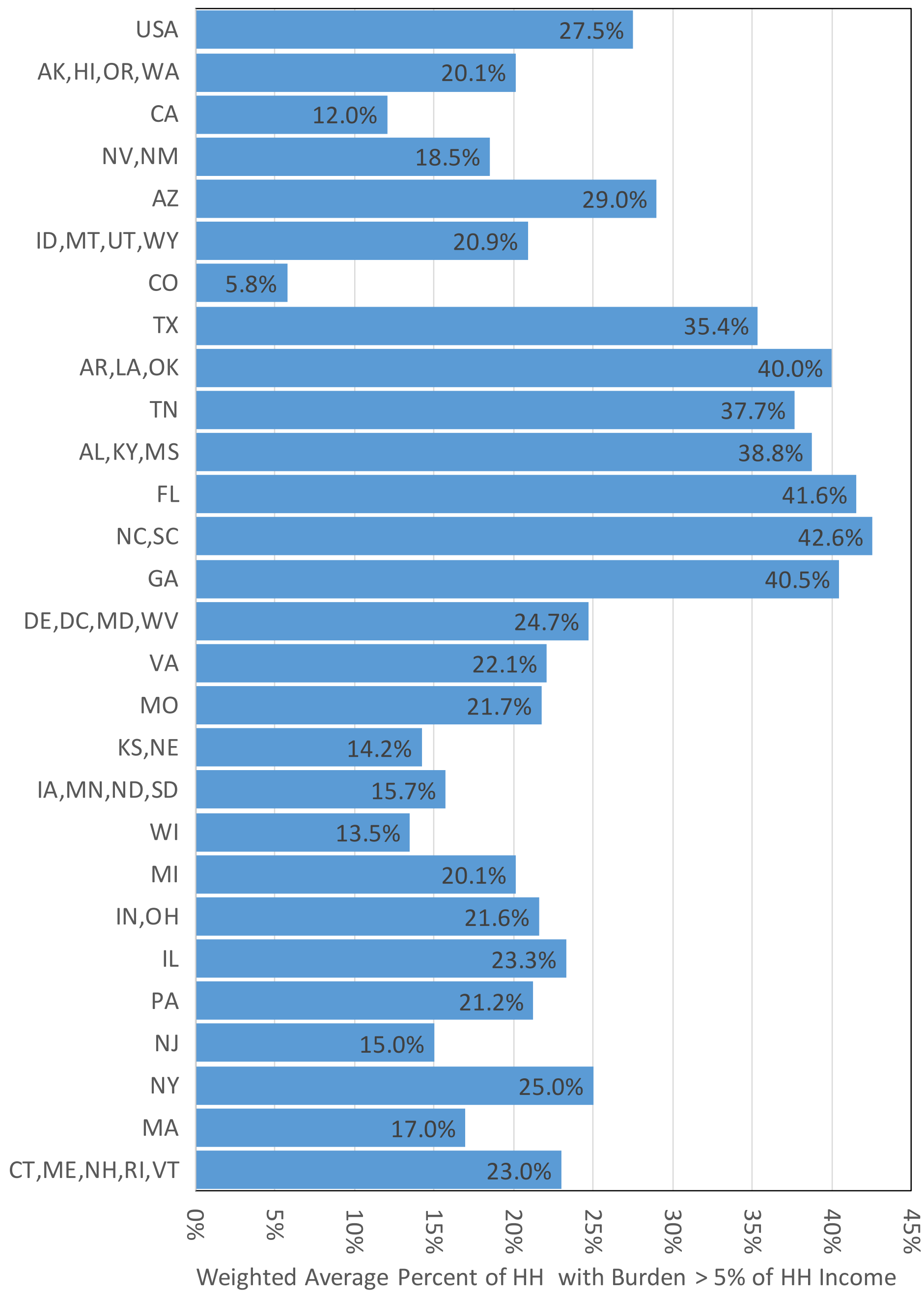

Figure 4.5. 2009 Average Percentage of Households with Electricity Cost Burdens Greater than 5 Percent of Household Income (EIA 2013)

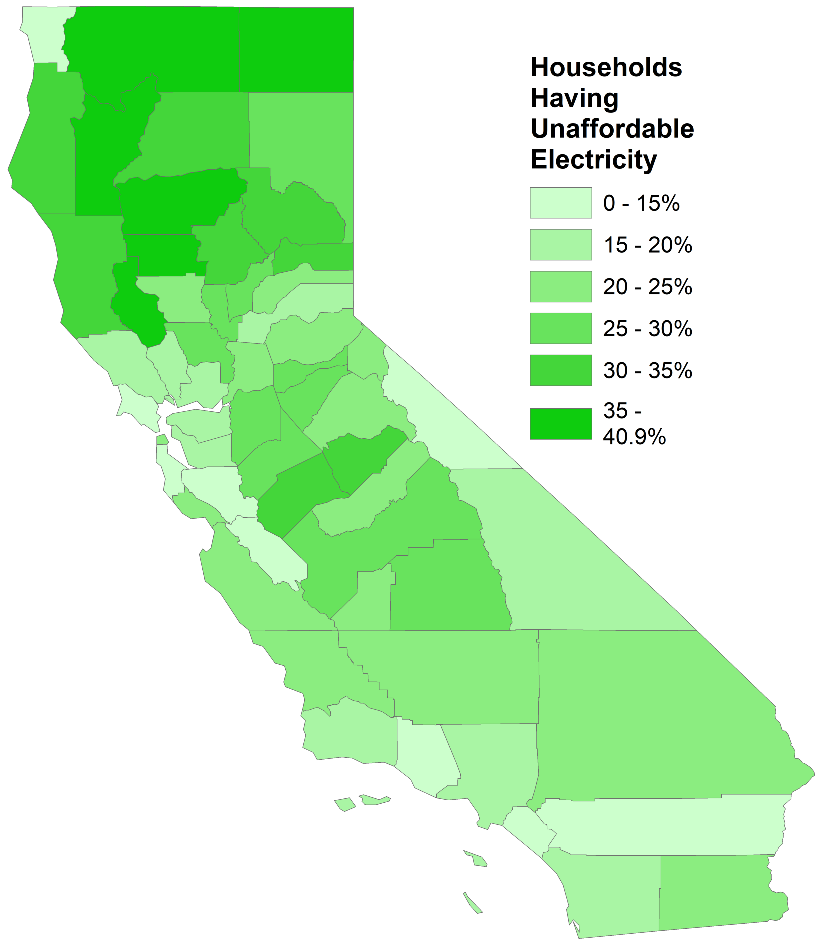

Figure 4.6. August 2017 California County-Level Residential Customer Affordability at the 3 Percent Cost-Burden Threshold

Figure 4.7 through Figure 4.9 illustrate the difference between simply examining average rates by customer class and consideration of electricity usage to estimate annual electricity cost (and the related downstream metrics associated with cost burden). These figures are derived using EIA Form 861 electricity sales data by utility and state (EIA 2018).

The movement of average rates over time may suggest whether electricity is becoming more or less affordable. For the same usage levels, rising average rates would indicate declining affordability of electricity, and declining average rates would indicate increasing electricity affordability. An index provides the means to track this metric over time. Tables 4.7 through 4.9 report the state and national annual average rate index by customer class, based on 2015 constant-dollar (adjusting for inflation) summarization of kilowatt-hour sales and revenue data reported to EIA (EIA 2019a) over the 2006–2018 period. Average rates reflect the total revenue divided by the total kilowatt-hours sold. Revenues include all billed usage, including demand charges and other applicable fees tied to usage.

As with the other index metrics discussed, numbers greater than 1 indicate that average rates have increased, net of inflation, relative to the base year, while numbers lower than 1 indicate rates have declined. For example, at the national level, average rates have been slowly declining in real terms for commercial and industrial customers, relative to 2006 levels, while residential average rates have increased slightly over the same period. State-specific indices show considerable variation by state and customer class. Variation in real average rates is greater among commercial and industrial customers, given the differing mix of industries in different states and differences in the classification of businesses into those rate classes. This highlights the difficulty in developing cost-burden metrics for nonresidential customers.

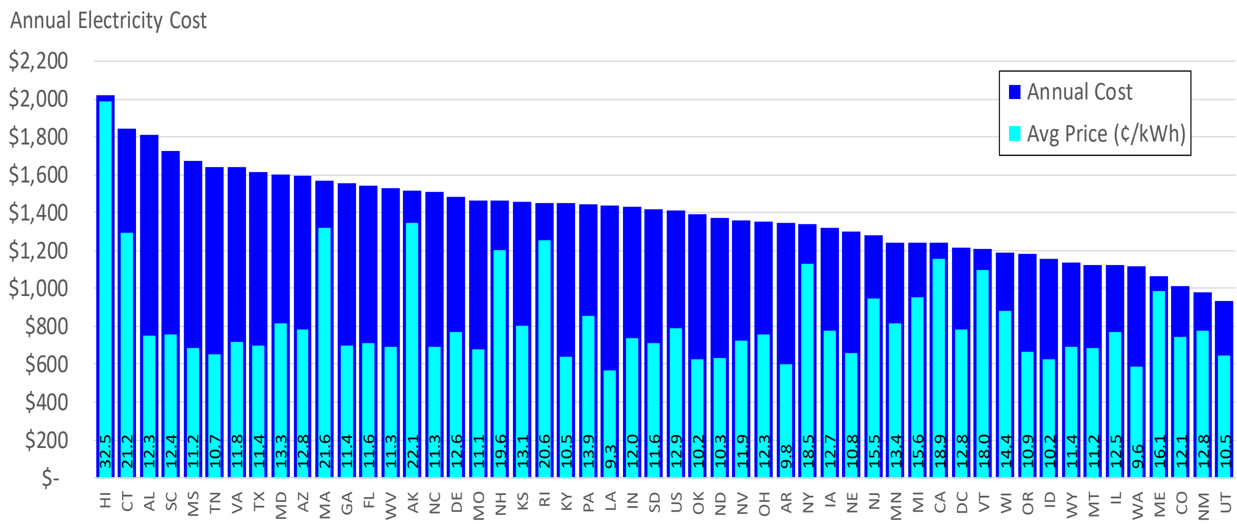

Figure 4.7. 2018 Residential Sector Average Electricity Cost per Customer and Rates by State (EIA 2019a)

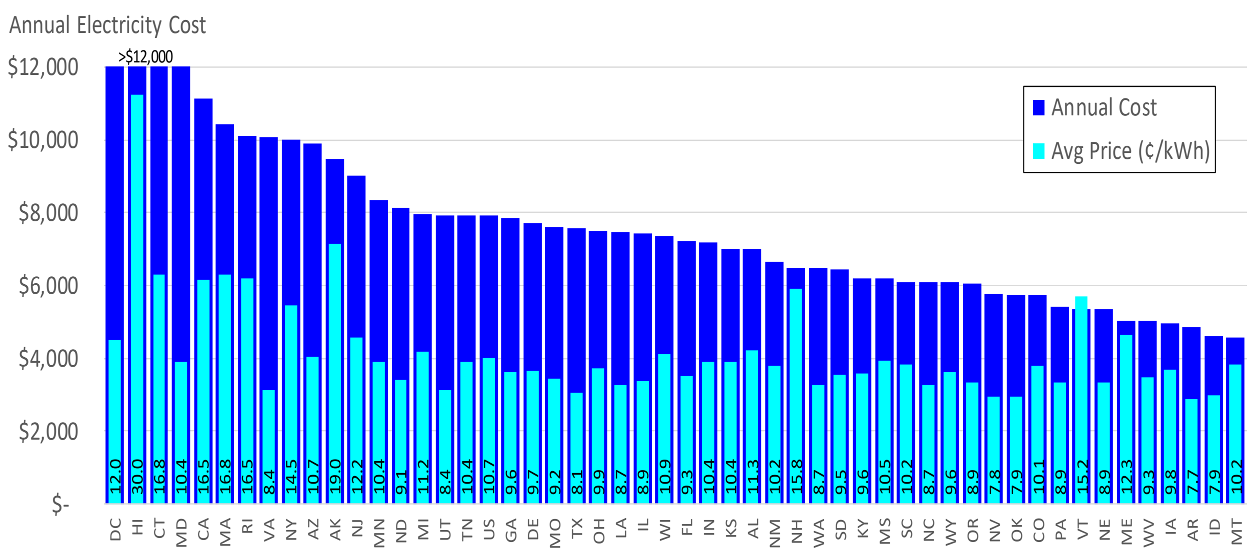

Figure 4.8. 2018 Commercial Sector Average Electricity Cost per Customer and Rates by State (EIA 2019a)

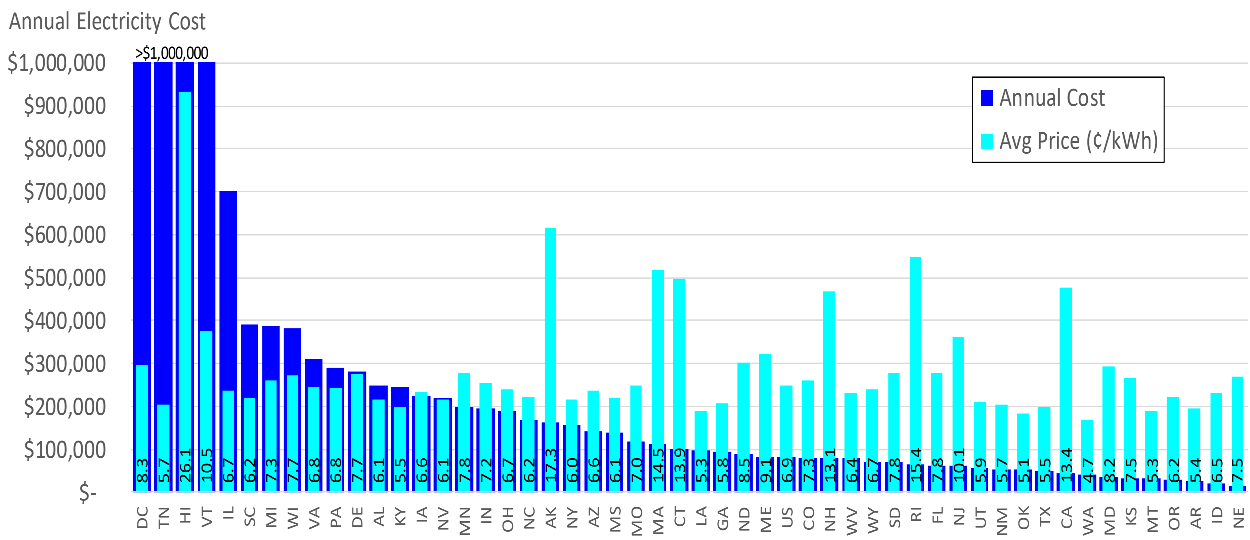

Figure 4.9. 2018 Industrial Sector Average Electricity Cost per Customer and Rates by State (EIA 2019a)

Table 4.7. 2006–2018 State and National Average Real Residential Rate Index (2006 = 1)

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
AK	1.000	0.994	1.065	1.128	1.043	1.076	1.064	1.067	1.126	1.177	1.167	1.205	1.194
AL	1.000	1.022	1.122	1.187	1.152	1.141	1.140	1.121	1.140	1.170	1.095	1.190	1.117
AR	1.000	0.946	0.992	0.998	0.947	0.915	0.920	0.941	0.931	0.969	0.890	0.969	0.880
AZ	1.000	0.998	1.040	1.111	1.109	1.068	1.058	1.086	1.105	1.132	1.040	1.105	1.089
CA	1.000	0.974	0.916	1.003	0.980	0.936	0.942	0.989	0.988	1.046	0.974	1.072	1.057
CO	1.000	1.000	1.065	1.085	1.158	1.136	1.125	1.154	1.183	1.183	1.069	1.135	1.075
CT	1.000	1.093	1.095	1.173	1.076	0.969	0.901	0.909	1.017	1.088	0.947	1.006	1.003
DC	1.000	1.095	1.227	1.351	1.340	1.224	1.093	1.111	1.119	1.155	1.040	1.091	1.034
DE	1.000	1.082	1.118	1.166	1.108	1.050	1.014	0.961	0.983	0.999	0.913	0.944	0.854
FL	1.000	0.959	0.983	1.071	0.956	0.920	0.888	0.873	0.919	0.903	0.796	0.860	0.821
GA	1.000	0.989	1.056	1.108	1.075	1.128	1.108	1.128	1.137	1.137	1.026	1.120	1.024
HI	1.000	1.001	1.324	1.014	1.142	1.347	1.409	1.386	1.386	1.118	0.944	1.060	1.115
IA	1.000	0.947	0.939	1.017	1.026	0.989	0.990	1.000	1.018	1.063	1.022	1.073	1.058
ID	1.000	0.999	1.072	1.228	1.222	1.152	1.235	1.309	1.365	1.405	1.292	1.351	1.315
IL	1.000	1.163	1.254	1.313	1.297	1.271	1.194	1.101	1.236	1.309	1.165	1.296	1.190
IN	1.000	0.979	1.030	1.131	1.109	1.114	1.127	1.171	1.224	1.244	1.112	1.256	1.170
KS	1.000	0.956	1.018	1.117	1.141	1.155	1.188	1.220	1.282	1.304	1.249	1.342	1.262
KY	1.000	1.009	1.071	1.171	1.164	1.189	1.182	1.222	1.271	1.282	1.177	1.304	1.199
LA	1.000	0.999	1.074	0.869	0.937	0.895	0.812	0.901	0.920	0.899	0.801	0.893	0.817
MA	1.000	0.944	1.006	0.994	0.833	0.801	0.790	0.831	0.915	1.049	0.922	1.014	1.040
MD	1.000	1.187	1.351	1.510	1.397	1.240	1.161	1.197	1.223	1.251	1.174	1.209	1.096
ME	1.000	1.157	1.114	1.104	1.078	1.009	0.937	0.911	0.967	0.994	0.916	0.971	0.933
MI	1.000	1.007	1.036	1.155	1.208	1.228	1.266	1.300	1.291	1.293	1.250	1.316	1.273

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
MN	1.000	1.023	1.058	1.122	1.154	1.144	1.153	1.184	1.203	1.223	1.172	1.251	1.231
MO	1.000	1.007	1.026	1.121	1.165	1.186	1.213	1.250	1.250	1.331	1.178	1.313	1.199
MS	1.000	0.938	1.018	1.027	0.967	0.951	0.935	0.972	1.016	1.025	0.870	0.958	0.923
MT	1.000	1.026	1.041	1.047	1.050	1.068	1.071	1.083	1.072	1.155	1.065	1.110	1.079
NC	1.000	0.999	0.991	1.073	1.051	1.024	1.054	1.055	1.064	1.092	0.980	1.003	0.993
ND	1.000	0.995	1.003	1.045	1.081	1.096	1.128	1.118	1.118	1.189	1.154	1.215	1.160
NE	1.000	0.994	1.013	1.121	1.139	1.137	1.189	1.215	1.226	1.260	1.176	1.245	1.167
NH	1.000	0.981	1.014	1.089	1.050	1.015	0.964	0.968	1.039	1.107	1.004	1.094	1.066
NJ	1.000	1.066	1.164	1.243	1.229	1.145	1.086	1.070	1.077	1.086	0.985	1.021	0.968
NM	1.000	0.968	1.043	1.073	1.093	1.093	1.103	1.122	1.179	1.208	1.062	1.187	1.124
NV	1.000	1.029	1.018	1.134	1.058	0.945	0.936	0.936	1.014	1.014	0.823	0.905	0.857
NY	1.000	0.979	1.028	1.011	1.048	0.979	0.917	0.971	1.038	0.963	0.833	0.892	0.875
OH	1.000	0.999	1.031	1.123	1.151	1.109	1.117	1.126	1.173	1.211	1.057	1.135	1.057
OK	1.000	0.979	1.016	0.976	1.014	1.011	0.984	0.996	1.026	1.045	0.948	1.044	0.959
OR	1.000	1.058	1.076	1.132	1.124	1.146	1.150	1.152	1.222	1.255	1.134	1.195	1.162
PA	1.000	1.024	1.051	1.099	1.168	1.168	1.085	1.084	1.127	1.162	1.091	1.155	1.079
RI	1.000	0.897	1.100	1.009	0.998	0.857	0.839	0.878	0.994	1.124	0.987	1.015	1.091
SC	1.000	0.989	1.044	1.128	1.105	1.116	1.154	1.164	1.212	1.232	1.107	1.210	1.101
SD	1.000	1.005	1.010	1.064	1.093	1.090	1.140	1.152	1.175	1.252	1.173	1.267	1.189
TN	1.000	0.968	1.083	1.164	1.117	1.160	1.140	1.119	1.152	1.162	1.060	1.149	1.097
TX	1.000	0.923	0.957	0.938	0.852	0.778	0.750	0.771	0.805	0.791	0.684	0.714	0.706
UT	1.000	1.044	1.037	1.092	1.084	1.071	1.146	1.194	1.217	1.262	1.167	1.212	1.104
VA	1.000	0.990	1.072	1.217	1.159	1.128	1.149	1.109	1.139	1.180	1.076	1.133	1.110
VT	1.000	1.018	1.027	1.085	1.103	1.100	1.117	1.114	1.139	1.123	1.035	1.106	1.074
WA	1.000	1.039	1.047	1.105	1.114	1.104	1.100	1.117	1.116	1.177	1.104	1.195	1.129
WI	1.000	1.004	1.040	1.106	1.137	1.120	1.106	1.122	1.138	1.181	1.096	1.141	1.096
WV	1.000	1.013	1.053	1.205	1.303	1.328	1.361	1.295	1.268	1.388	1.403	1.518	1.411
WY	1.000	0.980	1.011	1.090	1.083	1.069	1.120	1.156	1.190	1.257	1.162	1.240	1.184
US	**1.000**	**0.995**	**1.031**	**1.079**	**1.048**	**1.018**	**1.007**	**1.015**	**1.049**	**1.074**	**0.966**	**1.039**	**0.992**

Table 4.8. 2006–2018 State and National Average Real Commercial Rate Index (2006 = 1)

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
AK	1.000	0.992	1.085	1.189	1.107	1.148	1.102	1.144	1.254	1.286	1.258	1.330	1.276
AL	1.000	1.027	1.146	1.202	1.178	1.158	1.138	1.117	1.149	1.159	1.152	1.185	1.102
AR	1.000	0.954	1.031	1.060	0.988	0.969	0.968	0.997	0.997	1.043	0.997	1.017	0.879
AZ	1.000	1.004	1.056	1.147	1.125	1.074	1.045	1.069	1.102	1.144	1.106	1.099	1.069
CA	1.000	0.960	0.920	1.006	0.962	0.911	0.914	0.961	1.055	1.071	0.996	1.026	1.022
CO	1.000	0.980	1.089	1.067	1.149	1.134	1.103	1.152	1.175	1.161	1.089	1.105	1.077
CT	1.000	1.064	1.159	1.178	1.110	1.008	0.924	0.910	0.966	1.005	0.960	0.963	0.959
DC	1.000	1.037	1.127	1.159	1.133	1.042	0.943	0.927	0.950	0.943	0.889	0.875	0.857
DE	1.000	1.062	1.126	1.148	1.059	0.940	0.871	0.873	0.898	0.888	0.842	0.813	0.760
FL	1.000	0.948	0.968	1.065	0.938	0.895	0.862	0.829	0.873	0.844	0.765	0.787	0.751
GA	1.000	1.005	1.108	1.114	1.105	1.148	1.083	1.119	1.163	1.117	1.069	1.084	0.984
HI	1.000	0.990	1.317	0.999	1.147	1.369	1.435	1.391	1.394	1.106	0.978	1.049	1.121
IA	1.000	0.941	0.936	1.016	1.025	0.979	0.964	1.004	1.040	1.072	1.072	1.090	1.073
ID	1.000	0.949	1.041	1.220	1.202	1.113	1.168	1.242	1.309	1.320	1.276	1.288	1.214
IL	1.000	1.053	1.106	1.112	1.067	0.985	0.891	0.895	1.027	1.002	0.969	0.965	0.901
IN	1.000	0.981	1.028	1.125	1.105	1.105	1.112	1.164	1.212	1.197	1.182	1.221	1.155
KS	1.000	0.940	1.004	1.102	1.110	1.137	1.157	1.209	1.259	1.269	1.276	1.268	1.188
KY	1.000	1.028	1.083	1.159	1.169	1.201	1.196	1.173	1.281	1.292	1.276	1.296	1.199
LA	1.000	0.978	1.065	0.835	0.895	0.844	0.763	0.873	0.882	0.850	0.813	0.828	0.773
MA	1.000	0.949	0.986	0.970	0.886	0.834	0.784	0.799	0.827	0.897	0.856	0.859	0.866
MD	1.000	1.059	1.146	1.105	1.055	0.964	0.863	0.881	0.922	0.913	0.883	0.853	0.784
ME	1.000	1.007	0.995	0.992	0.955	0.897	0.816	0.823	0.894	0.887	0.830	0.817	0.793
MI	1.000	1.002	1.027	1.057	1.092	1.096	1.129	1.140	1.119	1.097	1.061	1.084	1.053
MN	1.000	1.037	1.071	1.102	1.137	1.111	1.106	1.172	1.234	1.181	1.203	1.256	1.188
MO	1.000	0.999	1.027	1.120	1.165	1.186	1.183	1.259	1.273	1.327	1.297	1.304	1.206
MS	1.000	0.916	1.010	0.987	0.937	0.914	0.871	0.938	1.002	0.983	0.869	0.909	0.893
MT	1.000	1.059	1.090	1.095	1.088	1.112	1.082	1.120	1.132	1.213	1.173	1.143	1.102
NC	1.000	0.994	1.002	1.085	1.079	1.018	1.063	1.067	1.066	1.063	1.016	0.977	0.966
ND	1.000	1.014	1.025	1.054	1.083	1.091	1.118	1.164	1.219	1.229	1.229	1.223	1.155
NE	1.000	0.999	1.026	1.149	1.161	1.167	1.192	1.210	1.224	1.234	1.208	1.189	1.148
NH	1.000	0.954	0.963	0.997	0.961	0.898	0.836	0.836	0.885	0.936	0.869	0.879	0.896
NJ	1.000	1.084	1.146	1.161	1.135	1.053	0.971	0.963	0.985	0.971	0.902	0.888	0.841
NM	1.000	0.980	1.087	1.079	1.072	1.083	1.077	1.114	1.182	1.192	1.086	1.124	1.073
NV	1.000	0.968	0.949	1.025	0.919	0.815	0.767	0.778	0.821	0.810	0.665	0.663	0.617
NY	1.000	0.992	1.029	0.976	0.996	0.922	0.857	0.867	0.906	0.868	0.790	0.794	0.748
OH	1.000	1.002	1.040	1.127	1.094	1.034	0.995	0.966	1.018	1.058	1.013	1.007	0.942
OK	1.000	0.968	1.027	0.909	0.960	0.942	0.880	0.932	0.968	0.928	0.897	0.929	0.865
OR	1.000	1.024	1.019	1.077	1.059	1.091	1.074	1.117	1.129	1.138	1.114	1.096	1.046
PA	1.000	1.000	1.003	1.042	1.075	1.016	0.930	0.902	0.951	0.949	0.879	0.847	0.799
RI	1.000	0.910	1.083	0.991	0.919	0.831	0.776	0.834	0.944	1.030	0.939	0.943	0.977

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
SC	1.000	0.980	1.049	1.117	1.109	1.107	1.112	1.137	1.182	1.181	1.153	1.168	1.073
SD	1.000	0.982	1.022	1.066	1.108	1.085	1.097	1.141	1.195	1.245	1.257	1.250	1.168
TN	1.000	0.980	1.092	1.171	1.149	1.165	1.133	1.091	1.134	1.122	1.085	1.110	1.039
TX	1.000	0.968	1.026	0.956	0.880	0.804	0.729	0.705	0.723	0.729	0.713	0.702	0.654
UT	1.000	1.031	1.043	1.120	1.103	1.097	1.169	1.187	1.216	1.240	1.227	1.181	1.101
VA	1.000	0.999	1.118	1.275	1.177	1.167	1.150	1.126	1.154	1.163	1.084	1.081	1.083
VT	1.000	1.017	1.014	1.076	1.085	1.082	1.076	1.096	1.089	1.090	1.054	1.045	1.039
WA	1.000	0.968	0.978	1.035	1.062	1.028	1.027	1.031	1.058	1.093	1.083	1.091	1.054
WI	1.000	1.002	1.051	1.116	1.128	1.120	1.100	1.112	1.122	1.141	1.094	1.087	1.037
WV	1.000	1.002	1.034	1.185	1.303	1.308	1.320	1.278	1.246	1.351	1.428	1.436	1.328
WY	1.000	0.952	1.010	1.131	1.113	1.105	1.146	1.191	1.233	1.271	1.269	1.289	1.218
US	**1.000**	**0.978**	**1.029**	**1.048**	**1.017**	**0.971**	**0.936**	**0.946**	**0.983**	**0.982**	**0.931**	**0.943**	**0.900**

Table 4.9. 2006–2018 State and National Average Real Industrial Rate Index (2006 = 1)

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
AK	1.000	1.060	1.172	1.112	1.161	1.235	1.286	1.199	1.191	1.109	1.125	1.187	1.203
AL	1.000	1.047	1.182	1.195	1.160	1.144	1.114	1.051	1.104	1.077	1.042	1.060	0.995
AR	1.000	0.968	1.077	1.089	0.984	0.974	0.982	1.007	1.007	1.049	0.998	0.982	0.830
AZ	1.000	1.018	1.099	1.147	1.097	1.047	1.004	1.026	0.995	0.972	0.910	0.955	0.926
CA	1.000	0.958	0.949	1.005	0.919	0.904	0.915	0.985	1.063	1.063	1.002	1.053	1.061
CO	1.000	0.984	1.078	1.059	1.108	1.088	1.029	1.080	1.109	1.103	1.053	1.065	0.989
CT	1.000	1.067	1.209	1.252	1.174	1.020	0.955	0.940	0.962	0.977	0.931	0.938	0.950
DC	1.000	0.517	0.584	0.471	0.419	0.359	0.278	0.276	0.421	0.445	0.430	0.395	0.381
DE	1.000	1.118	1.294	1.204	1.181	1.045	0.960	0.952	0.974	0.948	0.895	0.848	0.799
FL	1.000	0.980	1.011	1.179	1.095	1.010	0.914	0.861	0.895	0.937	0.851	0.848	0.810
GA	1.000	0.985	1.178	1.103	1.088	1.105	0.978	1.018	1.066	0.961	0.914	0.931	0.859
HI	1.000	0.989	1.371	0.982	1.153	1.427	1.506	1.450	1.464	1.129	0.978	1.065	1.159
IA	1.000	0.928	0.930	1.056	1.044	0.960	0.952	0.997	1.015	1.059	1.042	1.060	1.077
ID	1.000	1.048	1.187	1.410	1.342	1.281	1.345	1.479	1.551	1.613	1.536	1.559	1.443
IL	1.000	1.359	1.474	1.454	1.371	1.232	1.086	1.095	1.281	1.254	1.177	1.158	1.140
IN	1.000	0.968	1.066	1.155	1.141	1.144	1.132	1.193	1.246	1.239	1.215	1.282	1.175
KS	1.000	0.949	1.041	1.145	1.129	1.165	1.202	1.242	1.309	1.286	1.227	1.208	1.153
KY	1.000	1.088	1.139	1.196	1.208	1.198	1.188	1.244	1.243	1.210	1.212	1.193	1.099
LA	1.000	0.954	1.087	0.750	0.796	0.747	0.612	0.746	0.759	0.688	0.629	0.668	0.614
MA	1.000	0.968	1.030	1.059	0.998	0.932	0.853	0.886	0.852	0.914	0.877	0.895	0.892
MD	1.000	1.123	1.219	1.205	1.123	0.983	0.880	0.905	0.969	0.923	0.830	0.869	0.809
ME	1.000	1.550	1.251	1.109	0.990	0.915	0.800	0.823	0.882	0.910	0.870	0.876	0.827
MI	1.000	1.048	1.060	1.139	1.121	1.100	1.115	1.120	1.120	1.026	0.978	1.005	0.973
MN	1.000	1.041	1.057	1.160	1.126	1.109	1.079	1.153	1.103	1.162	1.188	1.169	1.176
MO	1.000	1.010	1.011	1.146	1.133	1.140	1.129	1.195	1.214	1.224	1.313	1.329	1.216

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
MS	1.000	0.951	1.062	1.092	1.012	0.996	0.925	0.932	0.976	0.984	0.836	0.852	0.826
MT	1.000	0.986	1.098	1.053	1.040	0.940	0.880	0.924	0.941	0.914	0.851	0.854	0.831
NC	1.000	1.023	1.004	1.126	1.129	1.044	1.083	1.074	1.091	1.100	1.031	0.999	0.953
ND	1.000	1.006	1.063	1.015	1.099	1.122	1.162	1.239	1.326	1.425	1.361	1.273	1.359
NE	1.000	1.010	1.073	1.231	1.236	1.258	1.339	1.404	1.423	1.453	1.424	1.402	1.303
NH	1.000	1.026	1.072	1.153	1.045	0.959	0.895	0.858	0.895	0.963	0.902	0.888	0.903
NJ	1.000	0.940	1.141	1.117	1.075	0.991	0.889	0.906	0.956	0.897	0.834	0.813	0.776
NM	1.000	0.968	1.085	0.994	1.015	0.985	0.912	0.997	1.028	0.990	0.881	0.927	0.814
NV	1.000	1.004	0.949	0.976	0.876	0.746	0.715	0.709	0.774	0.737	0.627	0.649	0.610
NY	1.000	0.895	0.949	0.872	0.887	0.751	0.627	0.613	0.613	0.590	0.543	0.526	0.510
OH	1.000	1.002	1.051	1.168	1.083	0.985	0.974	0.966	1.059	1.100	1.063	1.032	0.956
OK	1.000	0.950	1.018	0.852	0.930	0.904	0.816	0.873	0.920	0.848	0.773	0.822	0.741
OR	1.000	1.007	1.027	1.076	1.044	1.015	1.006	1.033	1.068	1.077	1.059	1.026	1.011
PA	1.000	1.012	1.007	1.065	1.105	1.055	0.960	0.926	0.978	0.960	0.889	0.863	0.824
RI	1.000	0.929	1.078	0.953	0.894	0.818	0.753	0.824	0.900	0.971	0.919	0.978	0.985
SC	1.000	0.988	1.091	1.205	1.149	1.135	1.124	1.114	1.170	1.123	1.104	1.105	1.055
SD	1.000	1.028	1.048	1.159	1.204	1.168	1.210	1.273	1.272	1.356	1.347	1.361	1.299
TN	1.000	0.968	1.150	1.277	1.202	1.252	1.202	1.057	1.074	1.049	0.933	0.934	0.876
TX	1.000	0.968	1.071	0.839	0.777	0.719	0.632	0.649	0.694	0.632	0.578	0.580	0.564
UT	1.000	1.037	1.040	1.116	1.105	1.098	1.173	1.226	1.267	1.299	1.276	1.216	1.123
VA	1.000	1.050	1.171	1.433	1.350	1.251	1.255	1.225	1.281	1.291	1.195	1.158	1.157
VT	1.000	1.037	1.052	1.082	1.084	1.068	1.060	1.136	1.072	1.092	1.046	1.029	1.011
WA	1.000	1.012	0.971	0.976	0.883	0.843	0.820	0.833	0.853	0.880	0.851	0.876	0.854
WI	1.000	1.017	1.046	1.109	1.092	1.119	1.089	1.095	1.109	1.133	1.081	1.065	1.043
WV	1.000	1.046	1.078	1.372	1.511	1.516	1.499	1.462	1.391	1.450	1.518	1.494	1.383
WY	1.000	0.992	1.068	1.171	1.184	1.221	1.320	1.396	1.440	1.495	1.468	1.445	1.339
US	**1.000**	**0.999**	**1.072**	**1.071**	**1.039**	**0.992**	**0.951**	**0.971**	**0.999**	**0.979**	**0.933**	**0.932**	**0.890**

4.7.3 Regional Level

As we move to larger geographic levels of aggregation, emerging metrics gain importance in their usefulness in reflecting performance against nationwide goals and objectives. Performance against national goals and priorities can be assessed by rolling up state and regional performance. The methodologies applicable to the affordability metrics are universally applicable at any geographic scale, and thus provide a consistent view of the metrics from the highest to the lowest spatial level.

Well-established cost-effectiveness metrics used as a matter of standard practice at the project and system level do not diminish in importance but are likely aggregated and averaged as the level of geographic aggregation rises. Cost-burden metrics will become increasingly important at the regional level in the future.

4.7.4 National Level

There is national interest in measuring the effect of grid modernization efforts on customer affordability. Nationally, DOE is looking for insights into how the technologies and policies they sponsor affect customer affordability. For the expected advances in technology to improve reliability, flexibility, resilience, security, and sustainability, it is important to know their financial effect on electricity customers. Costs will be incurred for new investments, but it may be possible to offset the costs passed on to customers using new products and services to provide benefits that mitigate annual net bills. These emerging affordability metrics provide a robust methodology for measuring and reporting affordability impacts nationally.

Figure 4.10 uses the 2017 EIA Form 861 data (EIA 2018) to estimate the affordability headcount at the state level. The weighted-average customer cost was derived using the utility-system–level data for each state. State-level Census ACS data on household income were used for the income portion of the cost-burden calculation. Two observations confirm the analyses previously discussed. The 2017 data confirm what was observed in the 2009 RECS data. Electricity affordability is lower in the southern and Appalachian states than in states with generally higher electricity costs, such as in the northeastern states. This likely is a function of the average household incomes being somewhat lower in the southern and Appalachian states and less natural gas is used during the heating season in those states, as shown in Figure 4.11. Second, although there is a concentration of decreased affordability in the southern states, there is wide variation across the country.

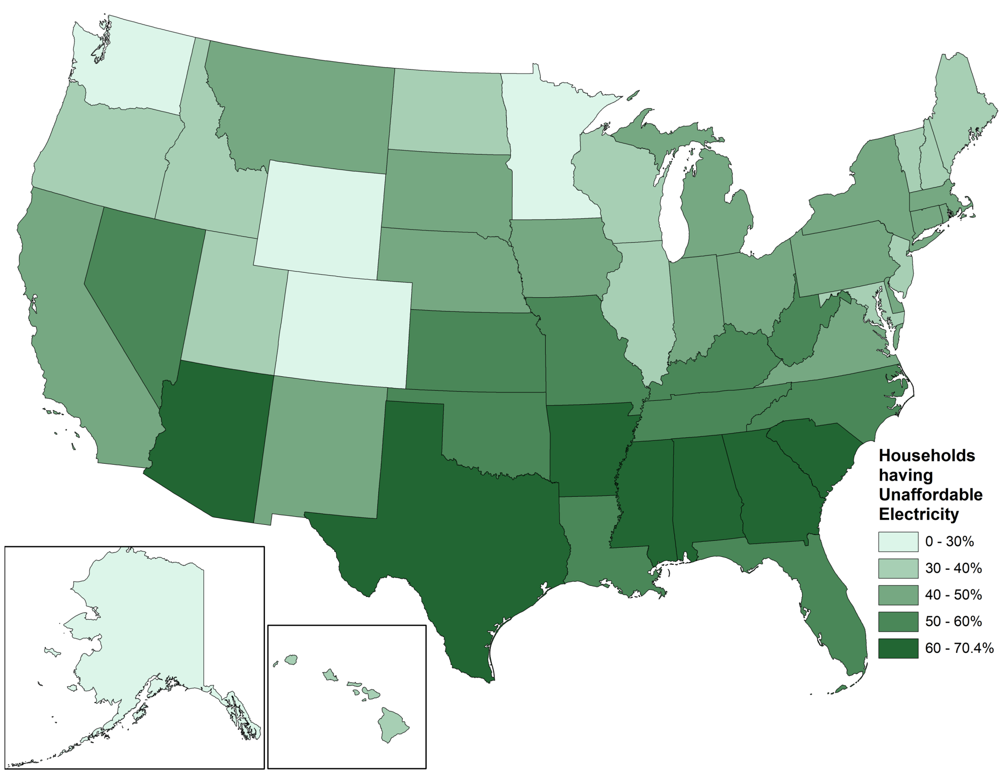

Figure 4.10. August 2017 State-Level Residential Customer Affordability at the 3 Percent Cost-Burden Threshold

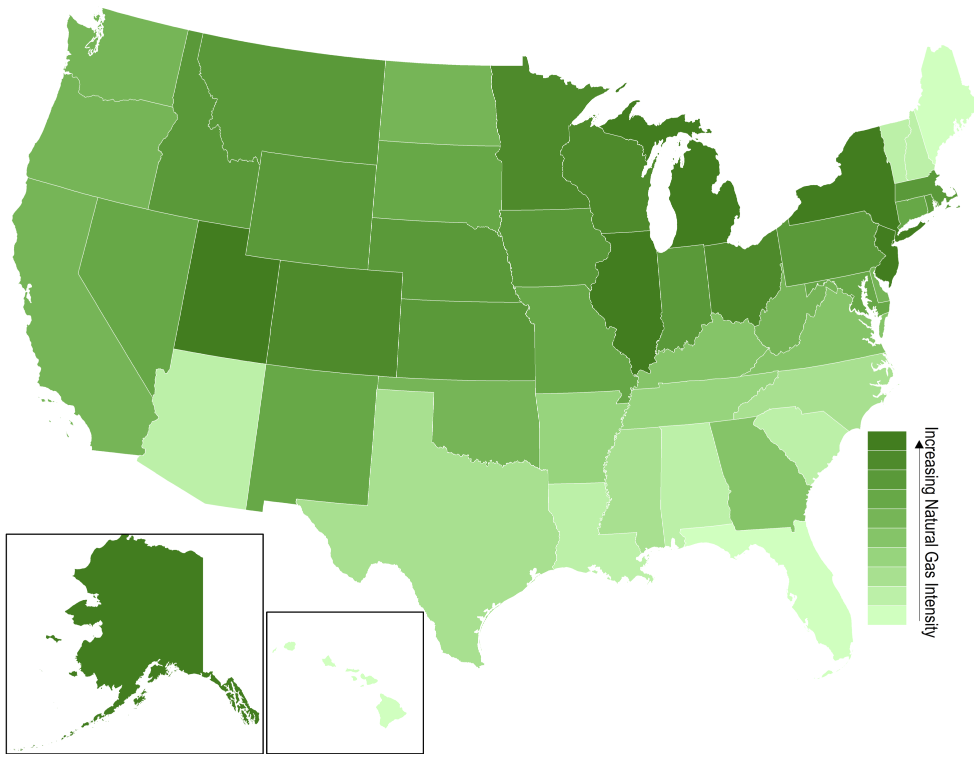

Figure 4.11. Residential Heating Season Natural Gas Intensity, Winter 2016-2017 (EIA 2019b)

Temporal variation in affordability also is important to understand as we look to measure the affordability impacts of ongoing grid modernization investments. The RECS microdata from the previous surveys (EIA 1996, 2004, 2009a, 2009b, 2013) were examined at the aggregate national level to identify whether trends exist in the effect of the selected affordability threshold on the number of households with affordable electricity. Figure 4.12 plots the data from those surveys, and Table 4.10 reports the range of percentage of households with affordable electricity at key threshold values. The curves are somewhat similar and have inflection points in the range of 4–6 percent threshold values. The 2001 curve seems to be a bit of an outlier. Each curve was derived using the same approach. None of them account for the effects of cost subsidies and other factors affecting the cost burden. These additional factors would be expected to have similar effects in each analysis year, thus the relative comparison is still valid.

Unfortunately, the 2015 RECS microdata altered the reporting of household income of the survey respondents such that the income bins are too coarsely defined to be of use for affordability metric estimation. The 2015 RECS also did away with the state groupings used in all previous RECS. Thus, the 2015 RECS is not comparable with any previous RECS microdata for spatial detail greater than Census divisions.

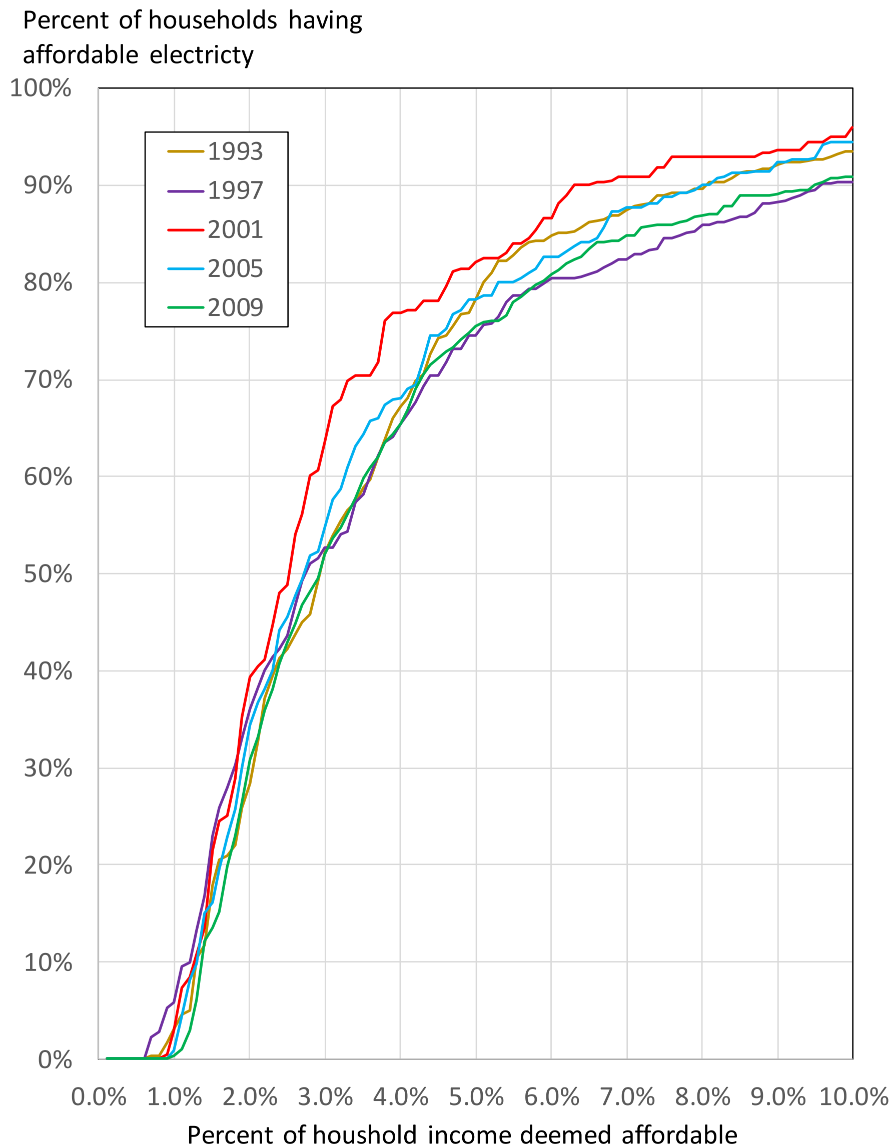

Figure 4.12. National-Level Residential Customer Percentage of Households with Affordable Electricity as a Function of Affordability Threshold Values (EIA 1996, 2004, 2009a, 2009b, 2013)

Table 4.10 takes slices of the curves in Figure 4.8 at the key threshold values (2–10 percent). These values suggest that baseline affordability varies over time (16 years) by about 6–12 percent depending on the threshold value selected, with wider variation in the lower thresholds. If 2001 were considered an outlier year, the variation would be even tighter. These ranges might inform the estimation of uncertainty associated with the affordability headcount metric.

Table 4.10. 1993–2009 Percent of Households having Affordable Electricity by Threshold Value from RECS Microdata

Threshold	1993	1997	2001	2005	2009
2%	28.4%	36.1%	39.3%	34.4%	30.8%
3%	52.1%	52.7%	63.5%	54.8%	52.0%
4%	67.3%	65.4%	76.9%	68.1%	65.4%
5%	78.3%	74.6%	82.1%	78.2%	75.5%
6%	84.9%	80.4%	86.6%	82.6%	80.9%
7%	87.5%	82.3%	90.9%	87.7%	84.8%
8%	89.6%	85.9%	93.0%	90.0%	86.9%
9%	92.1%	88.3%	93.7%	92.4%	89.1%
10%	93.5%	90.4%	96.0%	94.4%	90.9%

4.8 Customer-Data Use Cases for Metrics

Two use cases were developed to test the application of the residential affordability metrics. In partnership with the Alaska Microgrid Project (AMP), a sister GMLC project, the estimated customer costs of new advanced microgrid deployment were examined for their residential customer affordability impacts. A second project, done in cooperation with Southern California Edison, using their anonymized and summarized customer billing data, compared baseline metrics derived from public data sources to the same metrics derived from customer billing data from a large utility.

4.8.1 Alaska Microgrid Project

The GMLC program has funded the Alaska Regional Partnership, which conducted the AMP. The AMP designed renewable-based microgrids for three remote Alaskan villages—Chefornak, Kokhanok, and Shungnak—as a means of mitigating the extreme costs associated with transporting petroleum-based fuel to their remote locations for power generation. There is clear linkage with the affordability metric, because the reason for the AMP is to demonstrate that renewable resource solutions can reduce fuel costs, and therefore customer costs to villagers throughout Alaska. Figure 4.13 provides the geographic orientation of these villages in Alaska.

Because these and most remote villages in Alaska have been receiving state subsidies to offset the high cost of fuel for local electricity generation, the state has detailed monthly customer cost data (unpublished 2016 data provided by Alaska Energy Authority) for each village participating in the Power Cost Equalization or PCE program. These data net out the cost of the PCE subsidies to reveal the net monthly cost faced by the customers. Data were provided for GMLC purposes for each year in the 2010–2015 period. Consistent data series were identified for 103 individual villages, including Chefornak. Kokhanok, and Shungnak, which also are covered in the Census ACS data for household income. The villages range in size from towns of more than 1,000 people to tiny outposts with just a few residents. Some of the villages are grouped together in the PCE data, most likely indicating that they may share the same power generation resources.

The AMP has value for demonstrating the affordability metrics for two reasons. It covers the entire state with a consistent methodology for estimating customer cost and accounts for the subsidy portion received by customers to yield a true net bill. Every village is analyzed and reported using the same approach.

There are two limitations of the data. The data are not customer-specific data, like those most utilities would have. Thus, the reported costs represent residential customer averages at the village level. In the Alaska village case, the dwellings would be expected to be somewhat homogeneous, without great variation in floor space or heating demand. Therefore, the village average cost per customer may not be unreasonable. In addition, there are no customer-level income data. As mentioned, there are village-level household income ACS data for each of the 103 villages analyzed for 16 income bins.

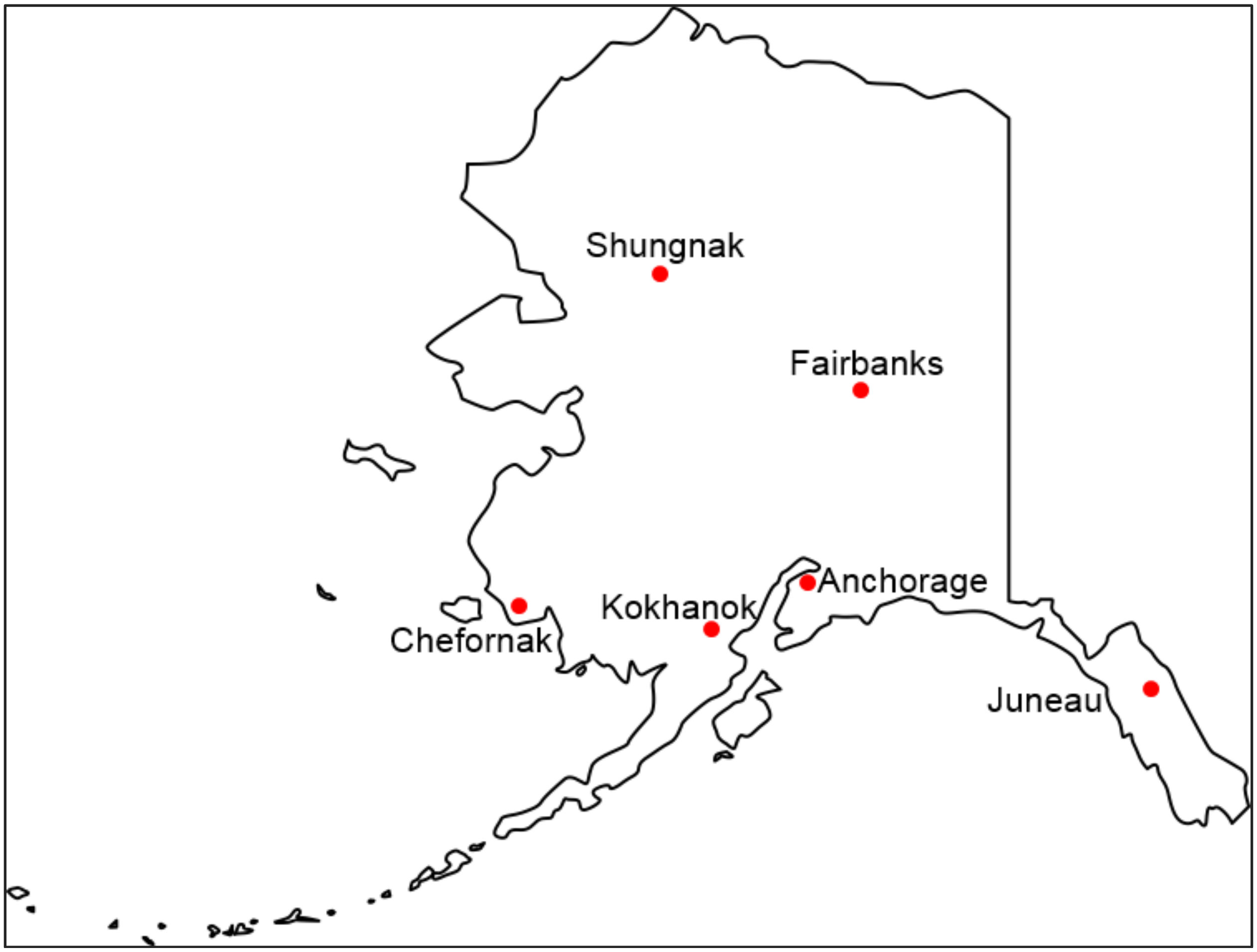

Figure 4.13. Relative Locations of Chefornak, Kokhanok, and Shungnak, Alaska

4.8.1.1 Baseline Metrics

Using the monthly summarized billing data for 103 villages, the village weighted-average customer cost burden was calculated by dividing the annual net cost per customer by the midpoint of each of the ACS household income bins, as described in Section 4.5.4, then weighting by the number of households in each income bin. These weighted-average village cost burdens are reported in the left third of Table 4.11. Based on the assumption that fuel use would be evenly split between heating and electricity generation, an affordability threshold of 3 percent was selected, consistent with the approach outlined by Colton (2011) and discussed in Section 4.5.1.1. The village-level affordability gap was calculated based on the approach documented in Section 4.5.2, and is shown in the center section of Table 4.11. The affordability gap index, which tracks the movement of the affordability gap through time, was calculated relative to 2010 and based on the approach in Section 4.5.3 and is shown in the right third of Table 4.11.

Table 4.12 presents results for all 103 villages analyzed, but some specific observations are possible for the AMP villages of Cherfornak, Kokhanok, and Shungnak. Through 2015, Chefornak shows slightly declining electricity affordability, based on increasing average cost burdens. The increasing cost burden is caused by increasing electricity costs, while incomes are not keeping pace with electricity costs. Electricity has become slightly more affordable in recent years in Kokhanok because of a slight drop in electricity costs, paired with stable incomes. Shungnak has seen flat-to-slightly-improved electricity affordability. As average electricity costs have declined slightly, incomes have remained relatively stable. Taken together, all 103 villages, in aggregate, have been relatively stable over the 2010–2015 period, and the overall average cost burden was just over 3 percent each year.

Table 4.13 lists the village-level affordability headcount metrics. Chefornak shows declining electricity affordability, based on more households facing electricity cost burdens above the affordable threshold in recent years. The increased proportion of households with electricity cost burdens above the affordable threshold is due primarily to increasing electricity costs. Kokhanok shows the opposite trend as the percentage of households facing electricity cost burdens above the affordable threshold has declined since 2010. The proportion of households in Shungnak with electricity cost burdens above the affordable threshold has fluctuated relative to 2010. Taken together, all 103 villages in aggregate have been relatively stable over the 2010–2015 period, and the overall affordable headcount was at just over 32 percent of households each year.

Table 4.14 illustrates the importance of the selection of the affordable threshold value. This table presents the affordability headcount metric and associated gap index for several alternative threshold values. By choosing alternative thresholds, the implications can change substantially. For example, given the results discussed for 3 percent thresholds, by increasing the affordability threshold to 5 percent or greater, intuitively, the percentage of households with affordable electricity grows substantially. At the aggregate village level, the number of households also changes markedly, but the overall trend reflected in the gap index remains level. However, the gap index for individual villages can fluctuate substantially.

The case of Alaskan villages is useful for testing the metrics using summarized data with the customer subsidies netted out. However, given the very small size of these locations and the special circumstances in which their electricity is generated and delivered, this case may not best represent the experience in the rest of the nation. However, the reliance on relative as opposed to absolute numerical comparisons makes the methods widely applicable and useful at any scale.

Table 4.11. Alaska Village Baseline Affordability Metrics (2010–2015)

Village	PCE Code	Average Proportion of Income Spent on Electricity (Customer Burden)						Affordability Gap Factor @ 3% Threshold						Affordability Gap Index (2010=1)					
		2010	2011	2012	2013	2014	2015	2010	2011	2012	2013	2014	2015	2010	2011	2012	2013	2014	2015
Chefornak	332310	3.21%	4.43%	4.81%	4.51%	3.43%	3.53%	1.07	1.48	1.60	1.50	1.14	1.18	1.00	1.38	1.50	1.41	1.07	1.10
Kokhanok	332100	5.56%	4.48%	6.22%	4.80%	5.38%	6.22%	1.85	1.49	2.07	1.60	1.79	2.07	1.00	0.81	1.12	0.86	0.97	1.12
Shungnak	331650	4.28%	3.74%	4.63%	4.32%	3.74%	4.42%	1.43	1.25	1.54	1.44	1.25	1.47	1.00	0.88	1.08	1.01	0.87	1.03
Villages Weighted Average	AK	3.08%	3.03%	3.13%	3.07%	3.13%	3.41%	1.03	1.01	1.04	1.02	1.04	1.14	1.00	0.98	1.02	1.00	1.02	1.11

Table 4.12. Alaska Village Baseline Affordability Headcount Metrics (2010–2015)

Village	PCE Code	Households with electricity cost burdens above the affordable threshold						Affordability Headcount Gap Index					
		2010	2011	2012	2013	2014	2015	2010	2011	2012	2013	2014	2015
Chefornak	332310	38.0%	51.4%	46.8%	47.0%	43.8%	37.5%	1.00	1.35	1.23	1.24	1.15	0.99
Kokhanok	332100	76.6%	47.9%	74.5%	57.5%	58.3%	64.2%	1.00	0.63	0.97	0.75	0.76	0.84
Shungnak	331650	44.4%	40.3%	50.0%	38.2%	37.5%	52.2%	1.00	0.91	1.13	0.86	0.84	1.17
Villages Weighted Average	AK	32.1%	33.1%	33.2%	32.9%	33.4%	36.5%	1.00	1.03	1.03	1.03	1.04	1.14

Table 4.13. Electricity Affordability Metrics for Alaska Villages using Alternative Threshold Values

Village	Income Threshold	Households with electricity cost burdens above the affordable threshold (%)						Affordability Headcount Gap Index					
		2010	2011	2012	2013	2014	2015	2010	2011	2012	2013	2014	2015
Chefornak	1.0%	69.0	94.4	96.1	96.4	92.5	95.5	1	1.37	1.39	1.40	1.34	1.38
	1.5%	66.2	75.0	74.0	80.7	80.0	79.5	1	1.13	1.12	1.22	1.21	1.20
	2.0%	50.7	70.8	67.5	73.5	66.3	72.7	1	1.40	1.33	1.45	1.31	1.43
	2.5%	38.0	51.4	62.3	65.1	48.8	55.7	1	1.35	1.64	1.71	1.28	1.46
	3.0%	38.0	51.4	46.8	47.0	43.8	37.5	1	1.35	1.23	1.24	1.15	0.99
	3.5%	32.4	51.4	46.8	47.0	37.5	37.5	1	1.59	1.44	1.45	1.16	1.16
	4.0%	32.4	36.1	46.8	39.8	31.3	28.4	1	1.11	1.44	1.23	0.96	0.88
	4.5%	22.5	36.1	35.1	38.6	31.3	22.7	1	1.60	1.56	1.71	1.39	1.01
	5.0%	22.5	27.8	35.1	38.6	17.5	22.7	1	1.23	1.56	1.71	0.78	1.01
	5.5%	18.3	27.8	33.8	27.7	17.5	13.6	1	1.52	1.84	1.51	0.96	0.74
	6.0%	18.3	20.8	22.1	27.7	12.5	13.6	1	1.14	1.21	1.51	0.68	0.74
Kokhanok	1.0%	100.0	95.8	95.7	97.5	91.7	94.3	1	0.96	0.96	0.98	0.92	0.94
	1.5%	91.5	79.2	93.6	92.5	87.5	90.6	1	0.87	1.02	1.01	0.96	0.99
	2.0%	87.2	79.2	93.6	77.5	85.4	88.7	1	0.91	1.07	0.89	0.98	1.02
	2.5%	87.2	62.5	74.5	65.0	64.6	71.7	1	0.72	0.85	0.75	0.74	0.82
	3.0%	76.6	47.9	74.5	57.5	58.3	64.2	1	0.63	0.97	0.75	0.76	0.84
	3.5%	70.2	47.9	74.5	42.5	54.2	58.5	1	0.68	1.06	0.61	0.77	0.83
	4.0%	70.2	43.8	63.8	37.5	50.0	52.8	1	0.62	0.91	0.53	0.71	0.75
	4.5%	48.9	41.7	61.7	37.5	45.8	45.3	1	0.85	1.26	0.77	0.94	0.93
	5.0%	48.9	41.7	61.7	35.0	45.8	39.6	1	0.85	1.26	0.72	0.94	0.81
	5.5%	48.9	41.7	57.4	35.0	43.8	39.6	1	0.85	1.17	0.72	0.89	0.81
	6.0%	48.9	41.7	57.4	35.0	43.8	39.6	1	0.85	1.17	0.72	0.89	0.81
Shungnak	1.0%	93.7	92.2	95.6	88.2	92.2	89.9	1	0.98	1.02	0.94	0.98	0.96
	1.5%	93.7	88.3	91.2	82.4	82.8	85.5	1	0.94	0.97	0.88	0.88	0.91
	2.0%	71.4	70.1	85.3	82.4	60.9	79.7	1	0.98	1.19	1.15	0.85	1.12
	2.5%	65.1	59.7	64.7	47.1	39.1	52.2	1	0.92	0.99	0.72	0.60	0.80
	3.0%	44.4	40.3	50.0	38.2	37.5	52.2	1	0.91	1.13	0.86	0.84	1.17
	3.5%	22.2	19.5	41.2	36.8	34.4	44.9	1	0.88	1.85	1.65	1.55	2.02
	4.0%	22.2	16.9	30.9	27.9	28.1	40.6	1	0.76	1.39	1.26	1.27	1.83
	4.5%	22.2	16.9	23.5	25.0	28.1	33.3	1	0.76	1.06	1.13	1.27	1.50
	5.0%	22.2	16.9	19.1	25.0	28.1	33.3	1	0.76	0.86	1.13	1.27	1.50
	5.5%	22.2	16.9	19.1	25.0	21.9	33.3	1	0.76	0.86	1.13	0.98	1.50
	6.0%	22.2	16.9	19.1	25.0	21.9	33.3	1	0.76	0.86	1.13	0.98	1.50
All Villages Weighted Average	1.0%	75.0	74.7	75.7	76.6	74.6	77.1	1	1.00	1.01	1.02	0.99	1.03
	1.5%	59.4	59.2	59.8	60.3	61.3	62.1	1	1.00	1.01	1.01	1.03	1.04
	2.0%	46.0	47.6	47.6	48.2	48.0	51.8	1	1.03	1.03	1.05	1.04	1.13
	2.5%	38.5	38.4	40.1	39.4	39.4	43.0	1	1.00	1.04	1.03	1.02	1.12
	3.0%	32.1	33.1	33.2	32.9	33.4	36.5	1	1.03	1.03	1.03	1.04	1.14
	3.5%	26.8	27.5	28.6	27.5	27.9	30.9	1	1.03	1.07	1.03	1.04	1.15
	4.0%	23.8	23.4	24.4	24.8	24.0	26.6	1	0.98	1.02	1.04	1.01	1.12
	4.5%	20.4	19.9	21.6	21.0	21.2	23.4	1	0.98	1.06	1.03	1.04	1.14
	5.0%	18.0	16.7	17.9	18.4	17.9	20.3	1	0.93	1.00	1.02	0.99	1.13
	5.5%	16.0	14.8	16.4	15.5	16.3	17.9	1	0.93	1.03	0.97	1.02	1.12
	6.0%	14.1	12.7	14.2	14.5	14.6	16.7	1	0.90	1.01	1.03	1.03	1.18

4.8.1.2 Alaska Microgrid Use-Case Affordability Impacts

To examine the affordability impacts of the proposed microgrid deployments in the three villages, the effective change in rates reported in each village study (Weimar and Hardy 2017a, 2017b, 2017c) were converted to bill impacts and applied as though the costs were incurred during the 2015 billing year. Table 4.14 summarizes the billing impacts that would have been expected if the customer-financed portion of the cost of the proposed microgrids for each village had been billed during 2015. The bill savings translate to improved affordability of electricity by examining the monthly bill impacts, which are summarized in Table 4.15. Table 4.14 also summarizes the associated impacts on the other affordability metrics from these cost savings.

Table 4.14. Billing Impacts of Proposed Microgrids in Remote Alaskan Villages

Village	Annual Effective Bill Savings from Microgrid Deployment[(a)]	Minimum Monthly Increase in Households having Affordable Electricity	Maximum Monthly Increase in Households having Affordable Electricity
Chefornak	24.3%	8.6%	60.0%
Kokhanok	43.9%	28.6%	38.2%
Shungnak	13.3%	0.0%	23.4%

(a) Source: Weimar and Hardy 2017a, 2017b, 2017c

In Table 4.15, the bill savings reported in Table 4.14 are applied in the "2015 Microgrid Monthly Bill ($)" section of the table. The resulting affordability impacts appear as subsequent sections of the table.

Affordability impacts do not exhibit a one-to-one relationship with the bill savings because affordability considers the income distribution of residential customers. Thus, as bills vary across the months in a year, the resulting burden of the electricity costs will manifest itself differently in different months. In higher-cost months, some higher-income bins in the distribution will cross the threshold into unaffordable electricity, while in lower-cost months, some lower-income bins in the distribution may cross the threshold into affordable electricity.

Table 4.15. Affordability Impacts of Proposed Microgrids in Remote Alaskan Villages

2015 Baseline Monthly Bill ($)													
Village	PCE Code	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Chefornak	332310	159	113	302	246	70	67	68	76	81	80	87	92
Kokhanok	332100	110	97	113	117	108	92	94	113	117	126	137	146
Shungnak	331650	136	117	129	108	88	97	89	90	101	121	133	157
2015 Microgrid Monthly Bill ($)													
Village	PCE Code	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Chefornak	332310	121	86	229	186	53	51	52	58	61	61	66	70
Kokhanok	332100	62	55	64	66	61	52	53	64	66	71	77	82
Shungnak	331650	118	101	112	94	76	84	77	78	87	105	115	136
Baseline Average Household Cost Burden (% of Income)													

Village	PCE Code	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Chefornak	332310	3.1%	2.2%	5.9%	4.8%	1.4%	1.3%	1.3%	1.5%	1.6%	1.6%	1.7%	1.8%
Kokhanok	332100	3.6%	3.2%	3.7%	3.8%	3.5%	3.0%	3.1%	3.7%	3.8%	4.1%	4.5%	4.8%
Shungnak	331650	3.3%	2.8%	3.1%	2.6%	2.1%	2.3%	2.1%	2.2%	2.4%	2.9%	3.2%	3.8%
Microgrid Average Household Cost Burden (% of Income)													
Village	PCE Code	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Chefornak	332310	2.3%	1.7%	4.4%	3.6%	1.0%	1.0%	1.0%	1.1%	1.2%	1.2%	1.3%	1.4%
Kokhanok	332100	2.0%	1.8%	2.1%	2.1%	2.0%	1.7%	1.7%	2.1%	2.1%	2.3%	2.5%	2.7%
Shungnak	331650	2.8%	2.4%	2.7%	2.2%	1.8%	2.0%	1.9%	1.9%	2.1%	2.5%	2.8%	3.3%
Baseline households with electricity cost burdens above the affordable threshold (percent of households)													
Village	PCE Code	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Chefornak	332310	55.7%	37.5%	93.2%	79.5%	22.7%	13.6%	13.6%	22.7%	22.7%	22.7%	22.7%	28.4%
Kokhanok	332100	64.2%	58.5%	64.2%	64.2%	64.2%	52.8%	58.5%	64.2%	64.2%	71.7%	71.7%	83.0%
Shungnak	331650	52.2%	52.2%	52.2%	52.2%	40.6%	44.9%	40.6%	40.6%	44.9%	52.2%	52.2%	68.1%
Microgrid household with electricity cost burdens above the affordable threshold (percent of households)													
Village	PCE Code	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Chefornak	332310	40.9%	28.4%	79.5%	72.7%	9.1%	9.1%	9.1%	13.6%	13.6%	13.6%	13.6%	22.7%
Kokhanok	332100	39.6%	37.7%	39.6%	39.6%	39.6%	37.7%	37.7%	39.6%	39.6%	45.3%	45.3%	52.8%
Shungnak	331650	52.2%	44.9%	52.2%	40.6%	33.3%	40.6%	33.3%	33.3%	40.6%	44.9%	52.2%	52.2%
Reduction in households with electricity cost burdens above the affordable threshold (percentage points)													
Village	PCE Code	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Chefornak	332310	14.8%	9.1%	13.6%	6.8%	13.6%	4.5%	4.5%	9.1%	9.1%	9.1%	9.1%	5.7%
Kokhanok	332100	24.5%	20.8%	24.5%	24.5%	24.5%	15.1%	20.8%	24.5%	24.5%	26.4%	26.4%	30.2%
Shungnak	331650	0.0%	7.2%	0.0%	11.6%	7.2%	4.3%	7.2%	7.2%	4.3%	7.2%	0.0%	15.9%
Percentage reduction in households with electricity cost burdens above the affordable threshold													
Village	PCE Code	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Chefornak	332310	26.5%	24.2%	14.6%	8.6%	60.0%	33.3%	33.3%	40.0%	40.0%	40.0%	40.0%	20.0%
Kokhanok	332100	38.2%	35.5%	38.2%	38.2%	38.2%	28.6%	35.5%	38.2%	38.2%	36.8%	36.8%	36.4%
Shungnak	331650	0.0%	13.9%	0.0%	22.2%	17.9%	9.7%	17.9%	17.9%	9.7%	13.9%	0.0%	23.4%

4.8.2 Southern California Edison Service Area Use Case

One goal of the affordability metrics effort has been to identify the trade-offs or analytical sacrifices required to use published data sources for estimating affordability metrics, in lieu of having unpublished utility billing data. Ideally, using public data would provide metric estimates not drastically different from the same estimates calculated using unpublished utility data. Testing this approach required cooperation with a utility willing to share unpublished data for analysis. We compared analysis using those data to that derived using public data sources outlined in this volume.

The authors secured the voluntary cooperation of Southern California Edison (SCE) an all-electric utility serving many of the counties in southern California. They provided unpublished anonymous monthly data similar to what EIA publishes under Form 861, but at the census tract level of summarization (SCE 2018). No customer personally-identifiable information or premise information was provided. These data include 2015, 2016, and 2017 monthly residential customer revenue, residential customer billed electricity use, and the number of customers by census tract for 2,777 census tracts in their service area. The data were analyzed to estimate baseline affordability metrics discussed in Section 3 and compared to the same metrics estimated using the EIA Form 861 published data for the same years and geography.

4.8.2.1 Baseline Metrics – Census Tract Level Results

Analyzing the published EIA Form 861 monthly data side by side with the SCE unpublished monthly census tract data for the same years revealed some expected differences in baseline affordability metrics. First, SCE's reporting at the census tract level of aggregation triggered required minimum thresholds of the number of customers for which data could be released given privacy concerns—generally reducing the customer count compared to the counts published by EIA at higher geographic summarization. This is evident in Figure 4.14, with SCE's census-tract-level reporting of the number of residential customers by month tracking below the aggregate total reported to EIA. The same holds for kWh electricity sales in 2015 and 2016, but not in 2017. Sales revenue also varies somewhat by month, but generally suggests that more revenues are included in the SCE data than the data EIA reports both monthly and annually, even though data for fewer customers are reported. This might be explained by a combination of factors such as any inflation adjusting or other standardization EIA may apply to the revenue data they report, or slight differences in the revenue classification between SCE's data shared for this analysis and how EIA classifies electricity revenue.

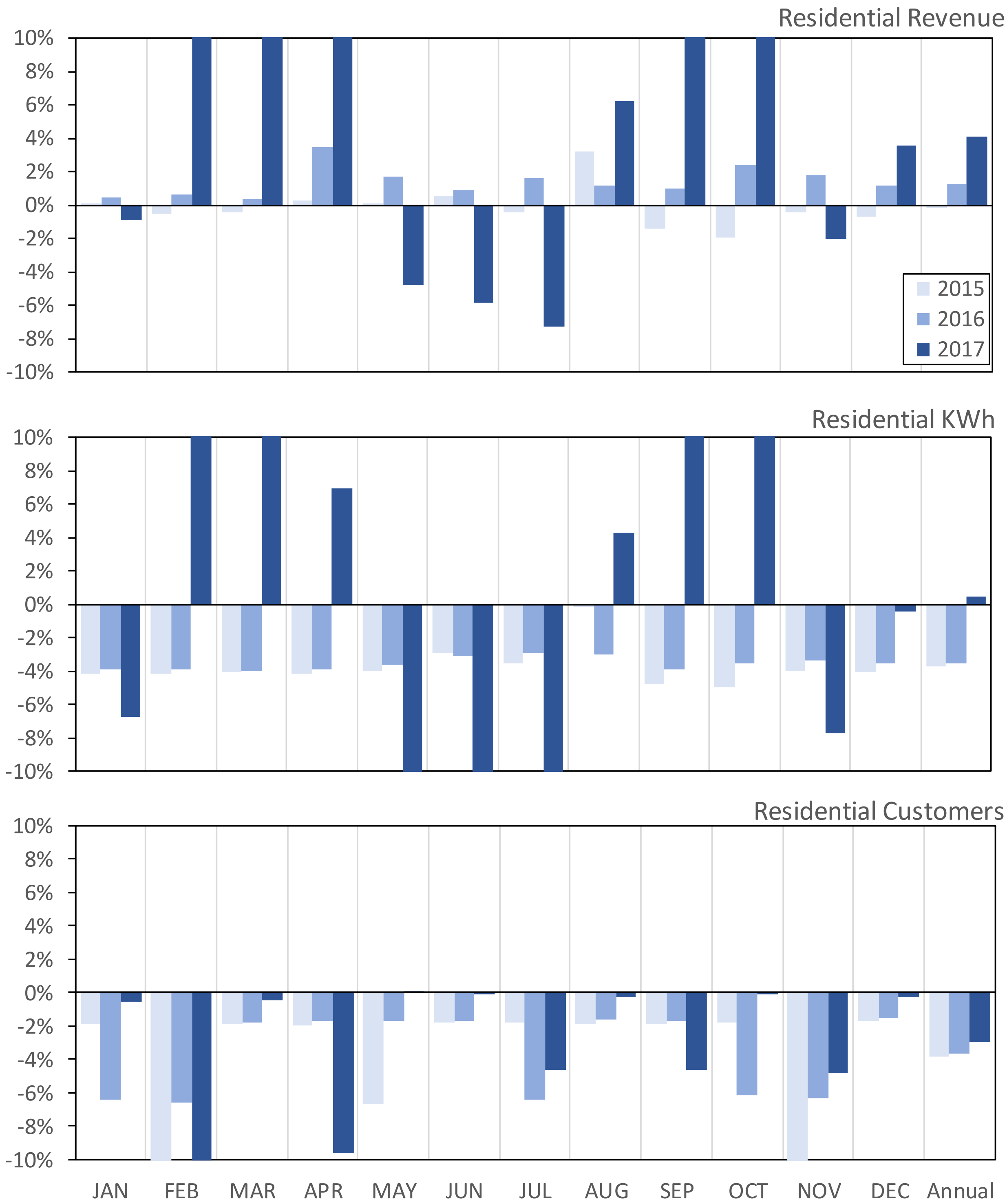

Figure 4.14. Comparison SCE-Supplied Data and Form 861 Public Data for Utility-Level Monthly Statistics 2015-2017.

Next, we compared the unpublished census-tract-level data on the number of customers provided by SCE and the same numbers derived from the Form 861 public data reported at the utility level and allocated to census tracts based on the application of the published county-level service territory information included in the Form-861 data and Census data on the number of households by tract. The results are shown in Figure 4.15 and are somewhat encouraging given the approach taken to allocate utility-level monthly data to counties and then to census tracts. Results are shown for August of 2017 as an example of a typical month during the cooling season, when air conditioning electricity use would be highest and natural gas use for space conditioning would be lowest. August of each year had similar results. The figure indicates that using public data to estimate the number of customers by census tract results in +/-10 percent or less difference from SCE unpublished counts in about 70 percent of the census tracts. We also analyzed January for each year and the results were similar. The location of tracts at variance with the SCE data are shown in Figure 4.16. The figure indicates generally with notable exceptions that customer counts using public data are more likely to undercount in somewhat rural census tracts (bigger tracts) and overcount in more urban census tracts (relatively small-sized tracts).

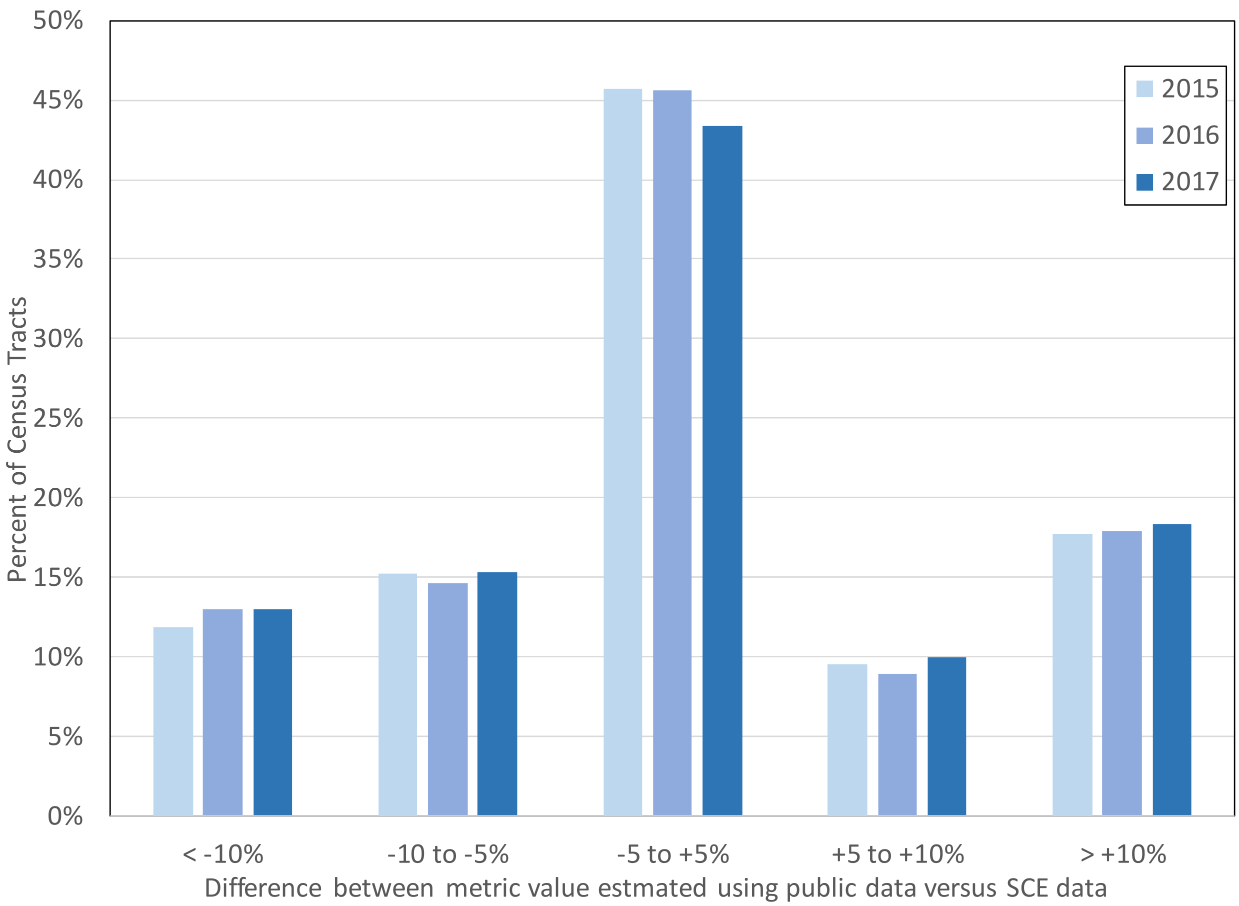

Figure 4.15. Variance in Results between Using Public Data and SCE-Supplied Data for August 2017 Residential Electricity Customer Counts for Census Tracts in the SCE Service Area

We also compared estimates of the affordability headcount metric calculated using the SCE unpublished data and the Form 861 public data. Figure 4.16 illustrates this comparison for August 2017. At an affordability cost threshold of 3 percent of household income, just 20 percent of the census tracts in the SCE service area fall within +/-10 percent of the number of households exceeding the electricity cost threshold when using Form-861 public data. Nearly 65 percent fall within +/-50 percent.

Figure 4.17 and Figure 4.18 summarizes these results spatially. The figure indicates generally with notable exceptions that using the Form-861 public data results in more relatively lower income tracts being identified that exceed the affordability threshold than using the SCE unpublished data. These are the blue areas on the map and correspond to most southern and eastern suburbs of Los Angeles, Ventura-Oxnard, and Orange-Irvine, among others. Conversely, the public data identifies fewer relatively higher income tracts than using the SCE data. These are the green areas on the map and correspond to such areas as Simi Valley, Thousand Oaks, Long Beach, and western Riverside County, among others.

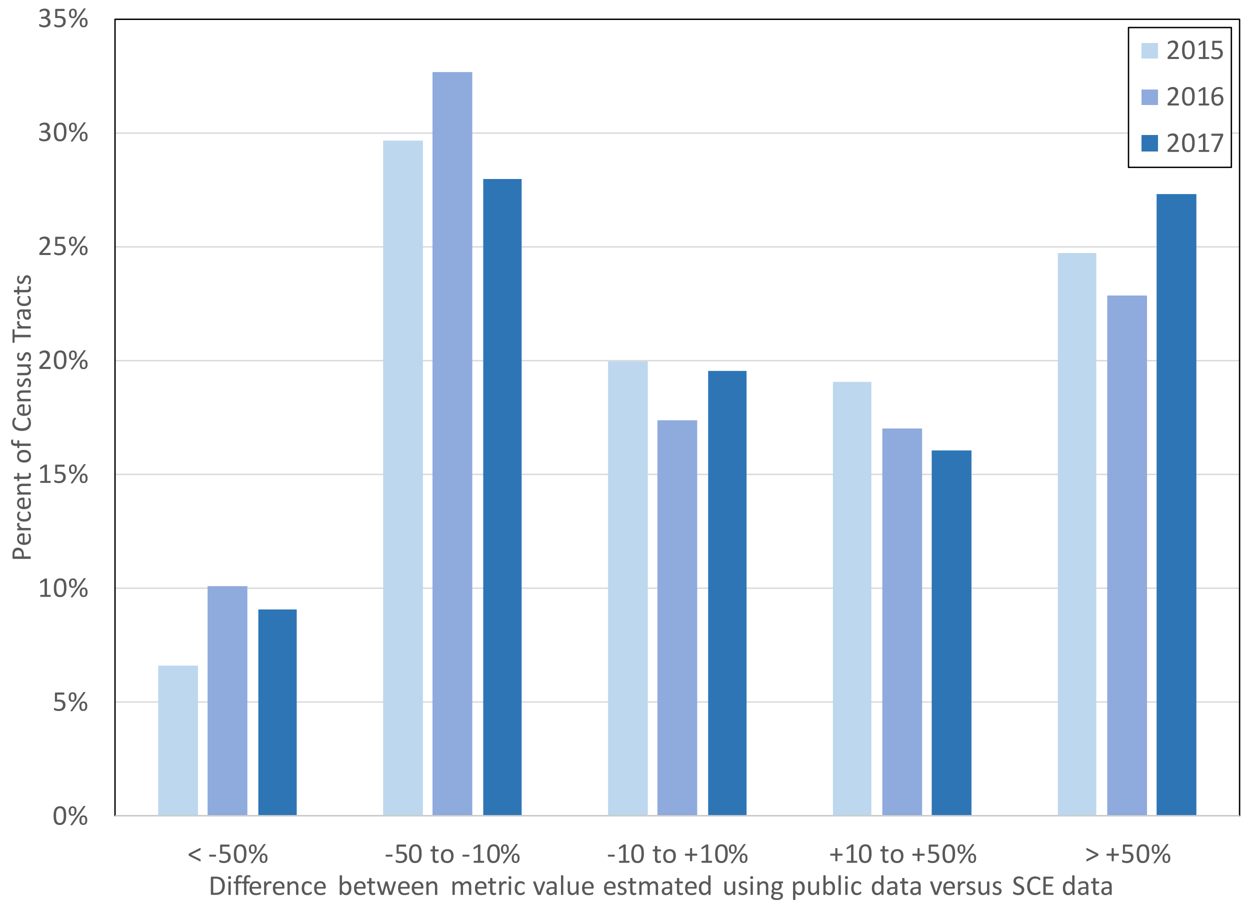

Figure 4.16. Variance in Results between Using Public Data and SCE-Supplied Data for August 2017 Households Exceeding a 3 Percent Electricity Affordability Threshold for Census Tracts in the SCE Service Area

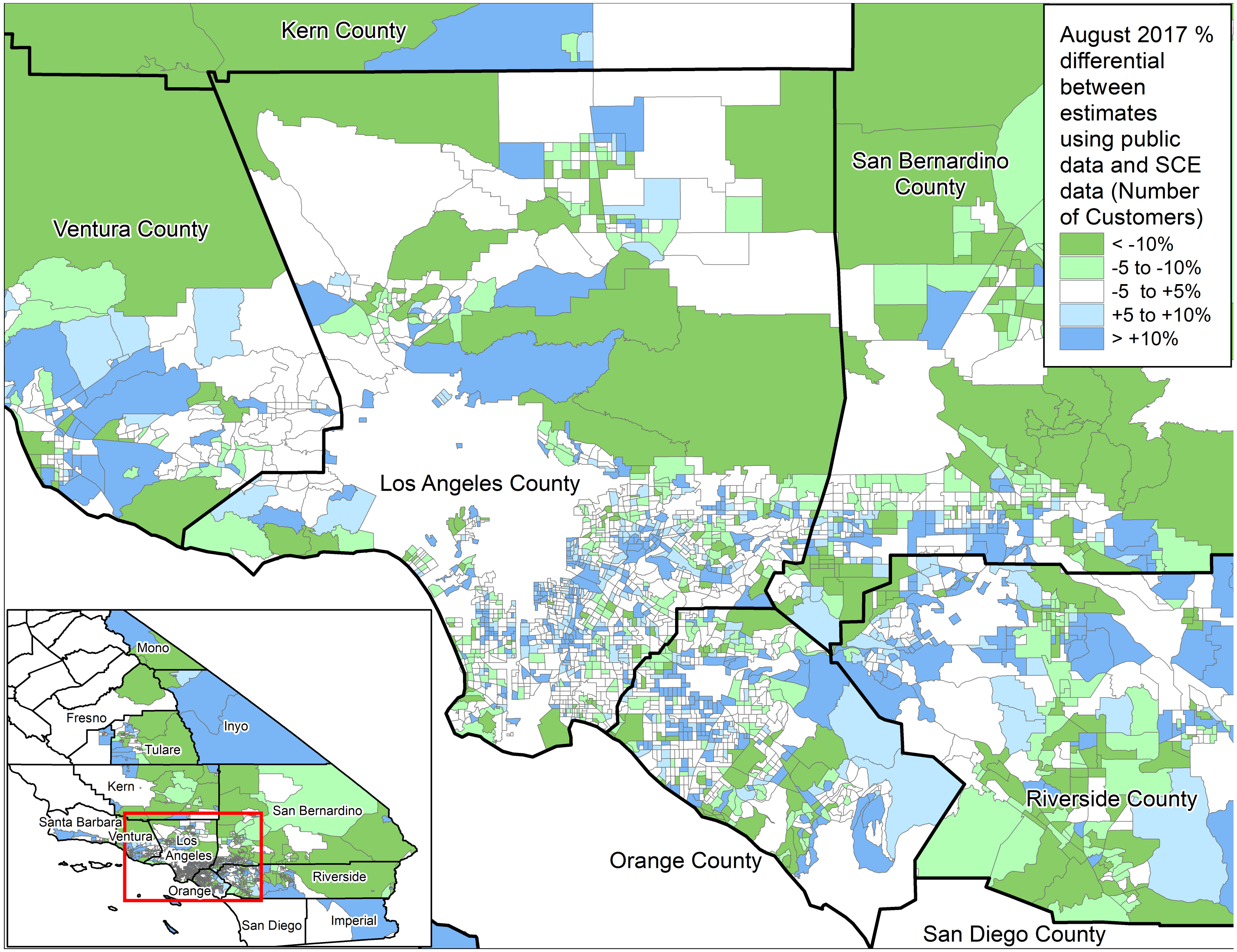

Figure 4.17. Spatial View of Variance in Results between Using Public Data and SCE-Supplied Data for August 2017 Residential Electricity Customer Counts for Census Tracts in the SCE Service Area

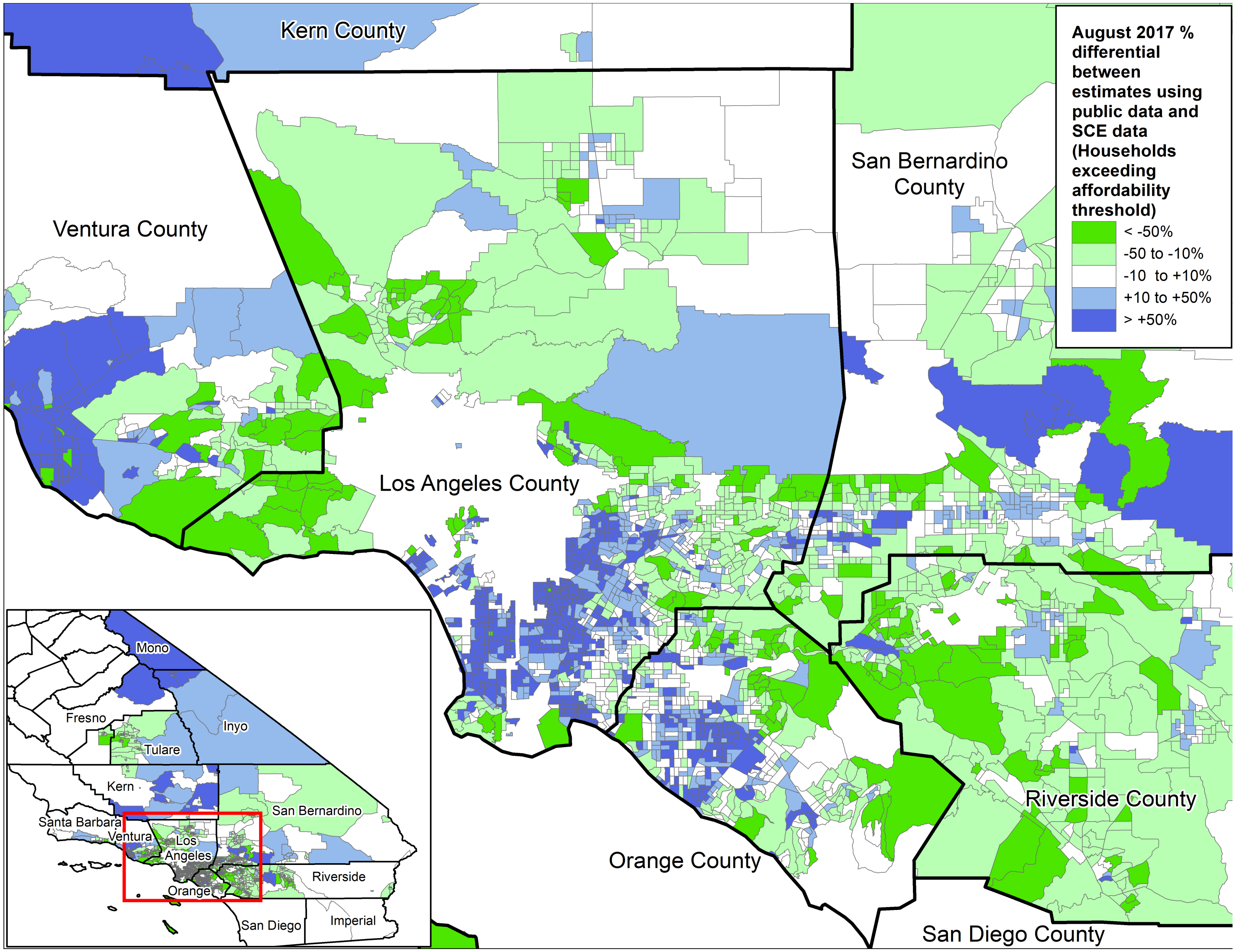

Figure 4.18. Spatial View of Variance in Results between Using Public Data and SCE-Supplied Data for August 2017 Households Exceeding a 3 Percent Electricity Affordability Threshold for Census Tracts in the SCE Service Area

4.8.2.2 Baseline Metrics – County Level Results

To evaluate the comparison at the county level, we estimated monthly average electricity cost burdens faced in each county of the SCE service area for 2015, 2016, and 2017. Cost burdens were estimated using the SCE-supplied data and the Form-861 monthly data. Tables 4.16–4.18 highlight the results. The green shading highlights combinations of county and month in which estimates using public data were within 25 percent of estimates based on the SCE data.

Table 4.16. 2015 Percentage Difference between Electricity Cost Burden Estimate Using Public Data and those Using SCE-Supplied Data

County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Fresno	19%	50%	79%	322%	105%	109%	138%	168%	245%	164%	73%	42%
Imperial	51%	73%	103%	175%	32%	35%	13%	26%	35%	89%	53%	72%
Inyo	-18%	-19%	-4%	9%	4%	8%	13%	30%	56%	98%	3%	-22%
Kern	7%	0%	17%	43%	10%	-1%	-1%	8%	33%	72%	14%	4%
Kings	-3%	-14%	-1%	-2%	-16%	-35%	-44%	-33%	-12%	2%	-8%	-10%
Los Angeles	4%	-5%	5%	13%	3%	9%	12%	7%	9%	11%	-3%	5%
Mono	-42%	-36%	-28%	-10%	5%	35%	84%	97%	152%	243%	-5%	-39%
Orange	-4%	-14%	-7%	-10%	-10%	2%	8%	-2%	-4%	-10%	-17%	-4%
Riverside	-13%	-21%	-15%	-30%	-27%	-24%	-26%	-29%	-22%	-23%	-25%	-9%
San Bernardino	3%	-4%	6%	9%	-1%	-4%	-12%	-12%	-5%	3%	-6%	2%
Santa Barbara	-8%	-21%	-10%	-5%	-7%	7%	42%	42%	48%	44%	-9%	-7%
Tulare	-5%	-15%	4%	3%	-16%	-33%	-38%	-30%	-6%	10%	-6%	-6%
Ventura	-9%	-19%	-10%	-11%	-11%	1%	12%	9%	10%	4%	-16%	-8%

Table 4.17. 2016 Percentage Difference between Electricity Cost Burden Estimate Using Public Data and those Using SCE-Supplied Data

County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Fresno	-10%	12%	39%	238%	82%	95%	105%	174%	133%	143%	70%	41%
Imperial	46%	39%	71%	288%	38%	6%	3%	25%	-6%	169%	45%	70%
Inyo	-26%	-24%	-7%	-5%	5%	1%	16%	25%	27%	45%	0%	-19%
Kern	-1%	1%	11%	33%	8%	-2%	-3%	12%	9%	44%	13%	7%
Kings	-3%	-6%	-2%	-8%	-14%	-39%	-31%	-34%	-25%	-15%	-1%	-7%
Los Angeles	-3%	-2%	5%	13%	6%	10%	5%	11%	10%	5%	-1%	2%
Mono	-54%	-50%	-39%	-44%	-5%	36%	70%	113%	80%	102%	-5%	-34%
Orange	-7%	-9%	-6%	-10%	-5%	4%	1%	3%	0%	-16%	-12%	-5%
Riverside	-15%	-16%	-16%	-34%	-23%	-25%	-33%	-30%	-28%	-31%	-24%	-11%
San Bernardino	-3%	-3%	4%	3%	2%	-8%	-18%	-16%	-11%	-7%	-4%	0%
Santa Barbara	-13%	-15%	-11%	-13%	-5%	14%	41%	70%	34%	15%	-10%	-8%
Tulare	-8%	-8%	2%	-3%	-16%	-35%	-32%	-24%	-21%	-8%	-2%	-4%
Ventura	-12%	-13%	-10%	-17%	-7%	2%	8%	18%	11%	-11%	-13%	-10%

Table 4.18. 2017 Percentage Difference between Electricity Cost Burden Estimate Using Public Data and those Using SCE-Supplied Data

County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Fresno	8%	-5%	-26%	-67%	-47%	33%	-28%	-45%	-63%	-89%	-61%	21%
Imperial	-29%	-29%	-53%	-74%	-21%	132%	34%	20%	-21%	-82%	-57%	6%
Inyo	47%	45%	7%	-30%	-7%	157%	24%	19%	-35%	-65%	-32%	107%
Kern	12%	3%	-18%	-47%	-8%	168%	62%	37%	-13%	-68%	-42%	66%
Kings	16%	4%	-7%	-40%	11%	309%	126%	129%	29%	-50%	-36%	82%
Los Angeles	11%	6%	-14%	-44%	-6%	144%	40%	29%	-13%	-60%	-31%	69%
Mono	146%	136%	89%	48%	23%	108%	-16%	-28%	-54%	-69%	-30%	152%
Orange	15%	8%	-9%	-35%	2%	149%	36%	33%	-9%	-51%	-21%	83%
Riverside	27%	20%	3%	-7%	34%	262%	124%	96%	29%	-40%	-11%	101%
San Bernardino	14%	6%	-12%	-38%	0%	193%	84%	66%	5%	-55%	-29%	72%
Santa Barbara	25%	26%	-1%	-29%	-1%	125%	-2%	-14%	-36%	-63%	-29%	91%
Tulare	20%	10%	-12%	-35%	12%	287%	133%	103%	28%	-56%	-35%	86%
Ventura	22%	17%	-3%	-27%	5%	159%	36%	24%	-11%	-54%	-21%	92%

Results for 2015 and 2016 are somewhat promising, as the analysis using public data came reasonably close in estimating the average cost burden for the core counties of the SCE service area. Counties on the outer edges of the SCE service area did not perform as well. This is likely because SCE is not the exclusive electricity provider or even the largest provider in those counties, and thus the smaller proportions of SCE customers there result in the public data overstating or over attributing SCE's influence in those counties. The 2017 results are not as encouraging, as several months of the year exhibit wide variance from the average burden estimates calculated using public data. More analysis is required to identify what factor may be causing this.

4.8.2.3 Comparison Assessment

Results of the comparative analysis of public data and utility-supplied data for the same service area are mixed for the one test case analyzed. More test cases would add clarity to the results. Results at the utility level are reasonable, given the known issues of nondisclosure by the utility as it follows customer privacy standards. Results were reasonably close for number of customers and electricity usage but varied more for sales revenue. At the census tract level, public data results in fairly close estimation of the number of customers, but comparison to residential metrics such as the affordability gap headcount are not encouraging for the SCE service area. Spatial examination highlighted some key differences manifest in urban versus rural tracts and in relatively low-income versus higher income tracts. Finally, the county-level results were relatively encouraging, as the average customer cost burdens for the core portions of the SCE service area generally agreed closely with the same estimates using unpublished data.

4.9 Affordability Map Dashboard Tool

To illustrate the spatial variation in specific affordability metrics, a geographic dashboard tool was developed. The tool displays the 50 states in one view and all their counties in another view. At the state level, 99 individual metrics are viewable, and 87 are viewable at the county level. Figure 4.19 and Figure 4.20 present screen shots of the tool as implemented online at https://gmlc.pnl.gov/affordability/.

The principal metric shown is the affordability headcount gap described in Section 4.5.4 above. The maps illustrate the percentage of households facing monthly electricity cost burdens above the affordable threshold, depending on the chosen affordability threshold percentage of household income. The user can select any month of 2016 or 2017 and any threshold income percentage from 2 to 6 percent to view a national picture of affordability by state or by county. Other metrics include monthly electricity cost per customer, average cost burden, and electricity rates. Specific metric values appear as the user hovers the mouse over the desired state or county.

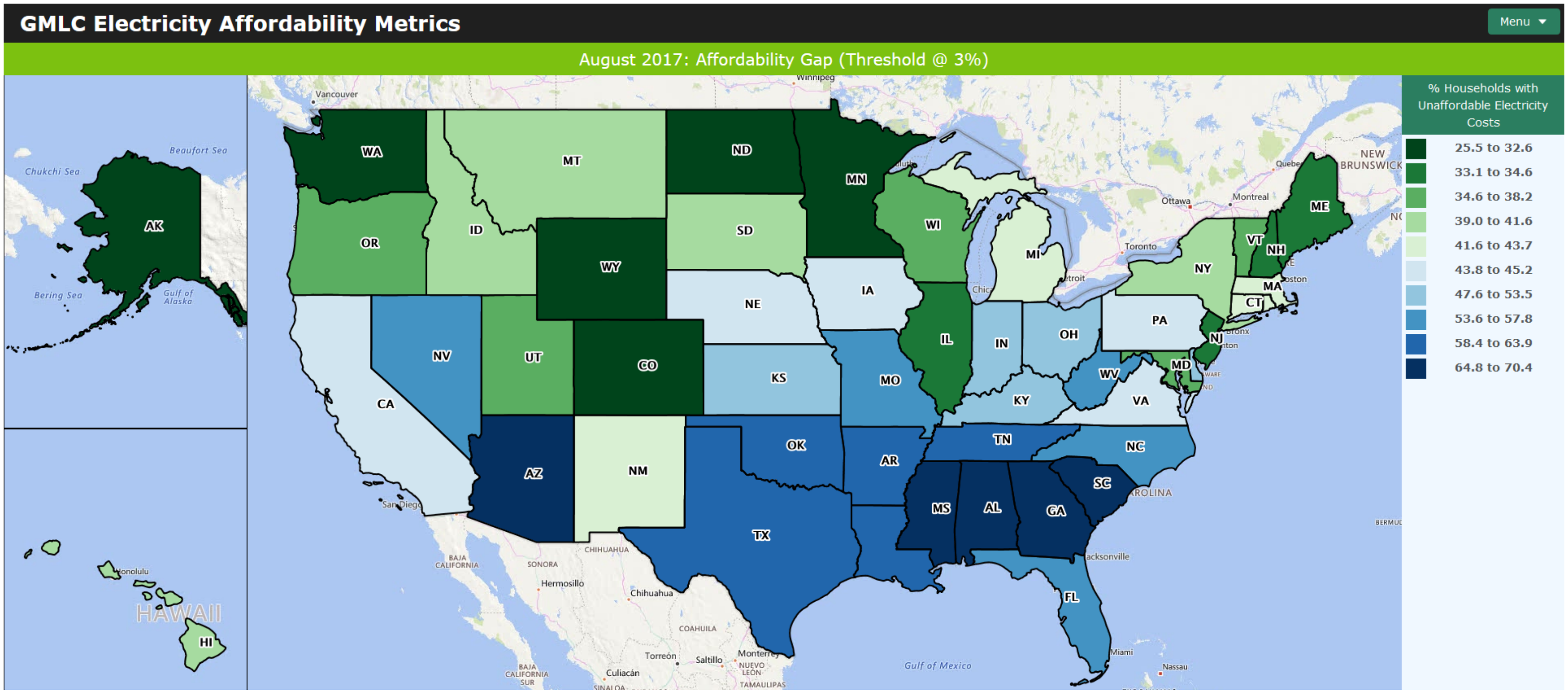

Figure 4.19. State View of the Affordability Dashboard Tool

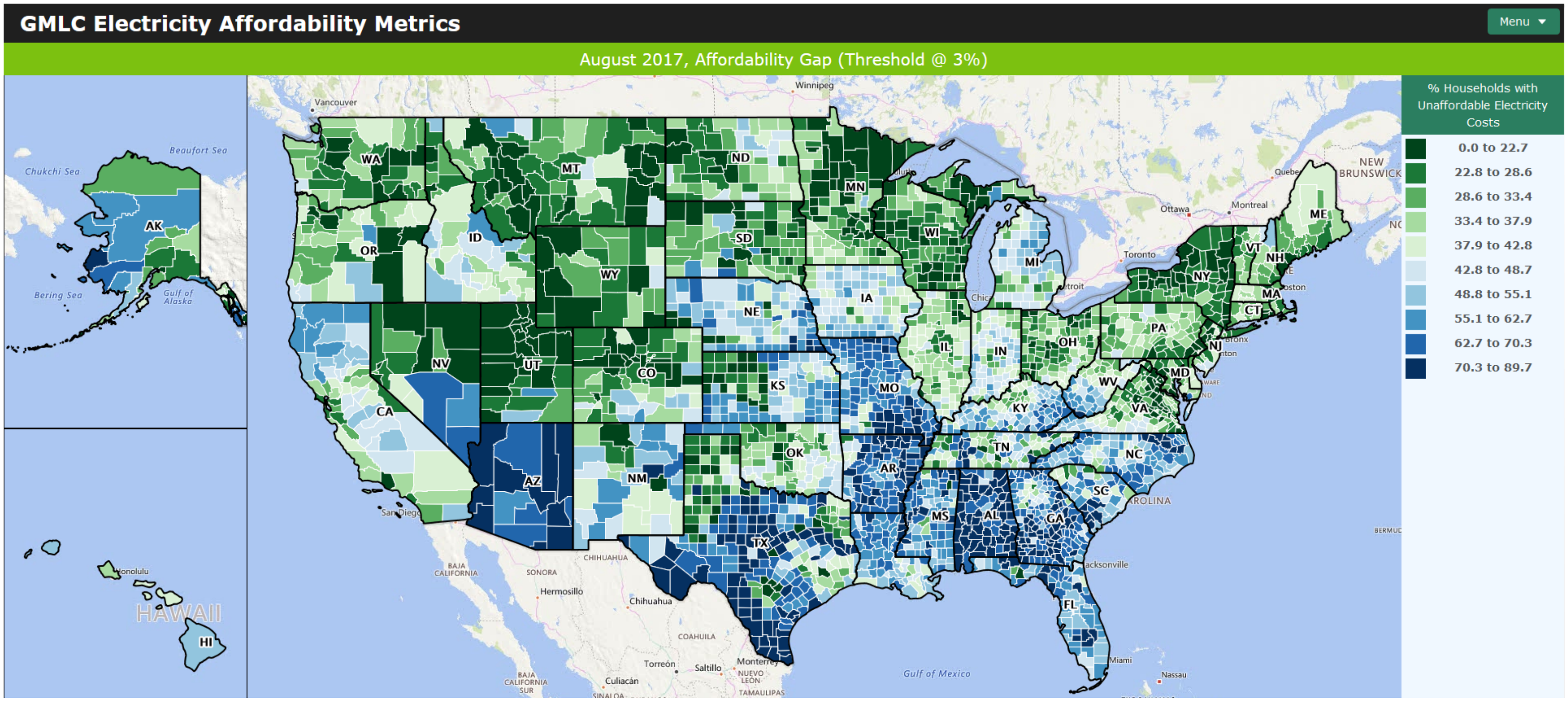

Figure 4.20. County View of the Affordability Dashboard Tool

4.10 Links to Other Metrics

Affordability is linked to all other metrics by the estimation of net costs. Changes in any other metric domain will have companion effects on cost-effectiveness and customer affordability. The fact that linkages to affordability exist is well understood. For example, utility investments to improve reliability, resilience, and flexibility may result in costs that would be passed on to customers—reducing the affordability of their electric service. At the same time, these investments may enable customers to take advantage of new demand-side services, which could result in benefits or credits to the cost of their electric service—increasing the affordability of their electric service. The metrics developed will enable the linkage of customer cost and benefit valuation with the investment required to modernize the grid.

What may be of interest is to engage the other metrics from the affordability context by asking the questions:

- What can be done in the flexibility or reliability domain to make electricity more affordable?
- What new products and services will a modernized grid enable that might offset costs required to enable them?
- What ancillary benefits from increased sustainability, resilience, and security can be translated to improved affordability?

These questions should be pursued in future research in which use cases can be developed to identify affordability impacts and be published for the benefit of stakeholders.

5.0 Next Steps

Three important areas would benefit from the momentum gained in the GMLC 1.1 Foundational Metrics project. More outreach is needed to develop metric test cases for the residential sector. This will lead to the necessary dissemination of the cost-burden approach to affordability metrics through additional stakeholder outlets and publications in relevant high-impact journals.

The metric reporting developed to date needs to be maintained and updated annually. The affordability map dashboard tool has been well-received and is currently fresh but will require updating to maintain relevance for examining affordability questions nationwide.

The commercial and industrial sector affordability metrics are nascent and require additional formulation and application to refine. With the development of the novel methodology to estimate affordability metrics for the commercial and industrial customer classes comes the need to develop use cases for those classes to test the analysis methodology. The approach is novel and needs to be applied to additional industries. We also hope to identify ways to generalize the approach to promote wider application and overcome the analysis burden currently required for even a single industry.

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Appendix A

Metrics Inventory

Appendix A

Metrics Inventory

A.1 Affordability

A.1.1 Data

	Categorization			Summary											Historical Supporting Data - Lagging Metrics				
Metric #	Sector	Category *(from list)*	Electric System Infrastructure Component *(from list)*	Metrics Name	Description	Motivation	Units	Metric Type *(from List)*	Metric Classification *(from List)*	Metric Use *(from List)*	Primary User *(from List)*	Secondary User *(from List - if applicable)*	Metrics Tense *(Lagging/ Leading)*	Applicable to Valuation Project *(Yes/No)*	Data Available? (Yes/No)	Geospatial Resolution *(from list)*	Temporal Frequency of Data Reporting *(from list)*	Citation/Data Source Reference #	Potential Issues Comments
1	Electricity	Affordability	All	Levelized cost of electricity (LCOE)	Total cost of installing and operating a project expressed in dollars per kilowatt-hour of electricity generated by the system over its life	LCOE has been used for calculating the cost-effectiveness of projects. By incorporating different categories of cash flows, different stakeholder interests can be examined.	$/MWh, $/kWh	Absolute	Outcome	Decision-making	Utility	Regulator	Leading	Yes				AFF1	
2	Electricity	Affordability	All	Internal Rate of Return (IRR)	The discount rate that makes the net present value (NPV) of the cost and revenue stream equal to zero	IRR has been used for calculating the cost-effectiveness of projects. By incorporating different categories of cash flows, different stakeholder interests can be examined. Rational investors would undertake projects as ranked by descending IRR order.	Percentage	Absolute	Outcome	Decision-making	Utility	Regulator	Leading	Yes				AFF1	
3	Electricity	Affordability	All	Simple Payback Period (SPP)	The length of time after the first investment that the undiscounted sum of costs and revenues equals zero	Easy to understand representation of cost effectiveness	# of years or months	Absolute	Outcome	Decision-making	Utility	Regulator	Leading	Yes				AFF2	While simple to calculate, it does not give as meaningful a result as the NPV or IRR, because it only tells how long it takes until the costs have been recovered, without providing an estimation of the total return. It does not capture any information about the time value of money, nor the impact over the full life of the project.
4	Electricity	Affordability	All	Net Revenue Requirements	The annual stream of revenue necessary to recover the total costs of a project including capital (in the form of depreciation), operating costs including fuel, financing costs including interest and required return on rate on equity, and taxes including both costs and incentives.	Revenue requirements are typically calculated and used on a company-wide basis, but the impacts of single projects on revenue requirements can be calculated by applying the rules on just the subset of costs applicable to the project.	$/year	Absolute	Outcome	Decision-making	Utility	Regulator	Leading	Yes				AFF3	

	Categorization			Summary											Historical Supporting Data - Lagging Metrics				
Metric #	Sector	Category *(from list)*	Electric System Infrastructure Component *(from list)*	Metrics Name	Description	Motivation	Units	Metric Type *(from List)*	Metric Classification *(from List)*	Metric Use *(from List)*	Primary User *(from List)*	Secondary User *(from List - if applicable)*	Metrics Tense *(Lagging/ Leading)*	Applicable to Valuation Project *(Yes/No)*	Data Available? (Yes/No)	Geospatial Resolution *(from list)*	Temporal Frequency of Data Reporting *(from list)*	Citation/Data Source Reference #	Potential Issues Comments
5	Electricity	Affordability	All	Avoided Cost	Net change in the costs of the overall system with the development of the specified project	Used by utilities and regulators for establishing the value of a project compared to its alternatives and for setting the value of distributed generation technologies	$	Absolute	Outcome	Decision-making	Utility	Regulator	Leading	Yes				AFF1	It can be a complicated calculation, subject to defining the boundaries of the analysis and adequately simulating the system. It captures items such as the energy avoided from other generators because of the new project (either a generator, demand response, or energy efficiency measures), capacity, substation, or transmission and distribution expansion.
6	Electricity	Affordability	All	Customer cost burden	Proportion of customer income devoted to purchasing desired level of electricity service	Foundational to estimating customer affordability	fraction	Numerical or intensity	Outcome	Learning/ Demonstration	Regulator	Consumer advocate; other advocacy groups	Lagging	Yes	Yes	National, Interconnection, regional transmission organization (RTO), State, utility service area, distribution system footprint	Annual/monthly	AFF4	Straightforward estimation for residential sector; more complicated for commercial and industrial sectors; public data sources for customer cost may have limitations compared to actual billing data.
7	Electricity	Affordability	All	Affordability gap factor	Indication of the difference between affordable customer costs and observed customer costs	Provides scale to the affordability question – How unaffordable are electricity costs on average?	factor or fraction	Numerical or intensity	Outcome	Learning/ Demonstration	Regulator	Consumer advocate; other advocacy groups	Lagging	Yes	Yes	National, Interconnection, RTO, State, utility service area, distribution system footprint	Annual/ monthly	AFF4, AFF5, AFF6	Straightforward estimation for residential sector; more complicated for commercial and industrial sectors; public data sources for customer cost may have limitations compared to actual billing data.
8	Electricity	Affordability	All	Affordability gap headcount	Number of households facing costs higher than an established affordable threshold	Provides scale to the affordability question – How many customers face electricity cost burdens above the affordable threshold?	Number of households or % of households	Absolute	Outcome	Learning/ Demonstration	Regulator	Consumer advocate; other advocacy groups	Lagging	Yes	Yes	National, Interconnection, RTO, State, utility service area, distribution system footprint	Annual/ monthly	AFF4, AFF7	Straightforward estimation for residential sector; more complicated for commercial and industrial sectors; public data sources for customer cost may have limitations compared to actual billing data.
9	Electricity	Affordability	All	Affordability gap index	Temporal index of affordability gap factor compared to a base year	Answers the question: Is electricity becoming more or less affordable?	index	Numerical	Outcome	Learning/ Demonstration	Regulator	Consumer advocate; other advocacy groups	Lagging	Yes	Yes	National, Interconnection, RTO, State, utility service area, distribution system footprint	Annual/ monthly	AFF4, AFF7	Straightforward estimation for residential sector; more complicated for commercial and industrial sectors; public data sources for customer cost may have limitations compared to actual billing data.
10	Electricity	Affordability	All	Affordability gap headcount index	Temporal index of affordability gap headcount compared to a base year	Answers the question: Are more or fewer customers facing electricity cost burdens above the affordable threshold?	index	Numerical	Outcome	Learning/ Demonstration	Regulator	Consumer advocate; other advocacy groups	Lagging	Yes	Yes	National, Interconnection, RTO, State, utility service area, distribution system footprint	Annual/ monthly	AFF4, AFF7	Straightforward estimation for residential sector; more complicated for commercial and industrial sectors; public data sources for customer cost may have limitations compared to actual billing data.

Citation/ Data Source Ref #	Citation/Data Source
AFF1	Short W., Packey DJ, & Holt T. 1995. A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies. NREL/TP-462-5173, National Renewable Energy Laboratory, Golden, Colorado. Available at: http://www.nrel.gov/docs/legosti/old/5173.pdf
AFF2	Hart R & Liu B. 2015. Methodology for Evaluating Cost-effectiveness of Commercial Energy Code Changes. PNNL-23923, Rev 1, Pacific Northwest National Laboratory, Richland, Washington. Available online at: https://www.energycodes.gov/sites/default/files/documents/commercial_methodology.pdf
AFF3	Hadley SW, Hill LJ, and Perlack RD. 1993. Report on the Study of Tax and Rate Treatment of Renewable Energy Projects. ORNL-6772, Oak Ridge National Laboratory, Oak Ridge, Tennessee. Available at: http://www.ornl.gov/~webworks/cpr/v823/rpt/68456.pdf
AFF4	Colton (2011) http://www.nyserda.ny.gov/-/media/Files/EDPPP/LIFE/Resources/2008-2010-affordability-gap.pdf
AFF5	Drehobl and Ross (2016) Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities. American Council for an Energy Efficient Economy, City, State.
AFF6	Heindl and Schuessler (2015) Dynamic properties of energy affordability measures. Energy Policy 86:123–132.
AFF7	Fisher, Sheehan, and Colton. 2013. "Home Energy Affordability Gap." Accessed online at: http://www.homeenergyaffordabilitygap.com/.

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