An Analysis of Municipalization and Related Utility Practices

Prepared for the District of Columbia Department of Energy and Environment (DC DOEE)

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Contents

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1. EXECUTIVE SUMMARY

The District of Columbia's Department of Energy and Environment (DOEE) retained Synapse Energy Economics (Synapse) to conduct a comparative study of recent electric utility municipalization efforts, as well as the innovative practices of leading utilities across the country. The purpose of this effort is to study the municipalization of utilities and to research innovative practices that can help utilities address the challenges and opportunities of the changing energy landscape in the 21st century.

Municipalization

Reliability concerns, high bills, a perceived loss of a local control, and a citywide sustainability policy with performance targets for energy savings, supply, and reliability are all reasons other communities have considered municipalization.

This report highlights four case studies that provide the most useful and relevant lessons for the District:

- Long Island, New York;
- Winter Park, Florida;
- Jefferson County, Washington; and
- Boulder, Colorado.

Process

The studied communities' process of municipalization can be summarized in four phases:

1. **Investigation**, wherein the communities identified their goals and assessed the technical, legal, and economic feasibility of municipalization;
2. **Acquisition**, wherein the communities completed comprehensive legal, engineering, and financial studies, underwent the negotiation or condemnation process, and completed the legal and financial transaction necessary to take legal ownership of the utility assets;
3. **Transition**, wherein the investor owned utility's (IOU) electric system operations, finances, customer service, and legal requirements were physically transferred, and the municipal electric utility ("muni") took responsibility for planning, maintaining, and operating the electric utility; and
4. **Fruition**, wherein the muni continues to operate day-to-day and progress in achieving the long-term objectives that motivated municipalization.

Costs and Benefits

The cost of municipalization was a key consideration for many communities. Most of the costs of municipalization were to acquire the electric system assets or build their own system, although the costs to operate the system and purchase power were significant as well. All communities studied in this effort purchased the already-built utility assets rather than build a new system, though each required some new physical assets to physically and operationally separate the newly formed muni's assets from the incumbent utility. The acquisition was financed through bonds or, in one case, a loan from the U.S. Department of Agriculture's Rural Utility Service program.

There are reasons why operating and maintaining a municipal utility can be lower cost than paying an IOU to own and operate the utility. First, municipal bonds typically have lower interest rates than investor-owned utility bonds, resulting in lower costs. Second, municipal utilities do not pay dividends to investors. Finally, municipal utilities are exempt from federal taxes. Lower costs can be passed on to customers in the form of lower rates.

On the other hand, municipal utilities face challenges that can result in higher costs. The acquisition cost for the municipalized infrastructure was in some cases significantly higher than what was being recovered by the IOU, putting immediate and long-lasting upward pressure on rates. Operationally, IOUs often have economies of scale that can lead to lower legal, management, and purchasing costs per unit of energy. Municipal utilities are not typically monitored closely by a public service commission, and inadequate auditing can allow poor utility practices to continue unchecked. Finally, the incumbent IOUs had a single, focused objective: safe, reliable power at least cost. Municipal utilities, on the other hand, also focused on the pursuit of other policy goals, which can result in higher electricity costs.

Within the three completed municipalization efforts studied, the inflation-adjusted asset valuation of electric distribution infrastructure ranges from $3,800 to $8,500 per customer, and from $125 to $475 per MWh sold. The range is considerable, not applicable to potential municipalization efforts in other communities, and it isn't clear to what extent the range is a function of the variety of physical equipment or the legal and political decision-making involved.

Key Findings

Although infrequent in the past several decades, municipalization is beginning to attract greater interest across the United States. Unfortunately, the limited number of municipalization efforts make it difficult to draw robust conclusions. The anecdotes that we have studied, however, suggest several findings:

First, municipalization tended to be spurred by a sense that a community's priorities and goals were different than that of the incumbent utility or the surrounding area. For example, a key motivating factor for Long Island was that it had a non-functioning nuclear power plant, poor reliability, and high customer bills. Winter Park perceived that reliability was worse there than in surrounding communities and had greater affinity for its oak trees than nearby jurisdictions with similar shade trees. Jefferson County was concerned about the loss of local influence when their IOU was purchased by a foreign investment team and began to eliminate local utility jobs. Boulder's culture places a higher regard on environmental stewardship than most communities in Colorado.

Second, there is little consistency between communities that formed municipal utilities.

- State laws governing municipalization varied widely across the country, and in several instances facilitated or hindered municipalization.
- The steps and the sequence of the investigation process varied from community to community.
- The level of interaction between the communities and tone of the response by incumbent utilities to municipalization ranged greatly.
- The interaction with and materials and process required by Public Utility Commissions was inconsistent across communities. In fact, we found no evidence of a framework or guidance used by PUCs to evaluate municipalization requests.
- The factors that motivated municipalization varied across the studied communities.
- Operational preparedness varied widely and luck played an important role in the difficulty encountered by a utility during the transition to a municipal utility.

Third, while the initial factors stimulating municipalization varied across communities, the drivers for municipalization became more complex, multi-faceted, and overlapping over time.

Fourth, benefits of municipalization that are more difficult to quantify were often an important factor in a communities' decision to municipalize. Some communities placed a higher value on improved reliability, reduced environmental impact, or more responsive customer service than reduced rates.

Fifth, one of the most significant challenges municipal utilities faced was acquiring and building the knowledge base to operate the utility. Experienced personnel with knowledge of the electrical system were critical for a successful transition from the IOU to the municipal utility, and they were difficult to identify and hire.

Lastly, the potential for innovation is greater for municipal utilities, but not every municipal utility has taken advantage of this increased flexibility. This may be due to a lack of vision, ignorance of cutting edge opportunities, poor management, or simply a deliberate reflection of the tenor their customers present.

Looking to the Future: Innovative Utility Practices

Both municipal utilities and IOUs are facing many of the same types of challenges and opportunities associated with a changing electricity landscape. In recent years, the industry has witnessed a dramatic proliferation of new technologies such as energy storage, distributed generation, and electric vehicles. These new opportunities are accompanied by changing expectations of customers who are becoming more active participants in the grid. New technologies have the potential to better meet customer demands and enable a cleaner, more affordable electricity system, but only if utilities take an active role in harnessing, managing, and supporting the use of these technologies.

In response to the proliferation of these technologies, forward-looking jurisdictions across the country are undertaking a range of innovative activities. This report explores several of these activities:

1. New approaches to distribution system planning and management,
2. Efforts to integrate and manage electric vehicles,
3. Innovative rate designs and methods for valuing distributed energy resources, and
4. A shift toward outcome-based utility regulation.

Distribution System Planning and Operation

Different approaches to distribution system planning and control are required to plan for increasing penetrations of electric vehicles, dispatch flexible-demand resources, manage two-way reversible power flows from distributed generation and storage, and strategically deploy distributed energy resources in the most beneficial locations. Two of the approaches being employed by forward-looking utilities are:

- **Distribution planning practices**: Jurisdictions such as California and New York have established detailed requirements for distribution system planning. Such practices include forecasting distributed energy resources and reporting distribution system data at a very granular level, such as providing substation 8760 hourly load data.

- **Utilizing distributed energy resources to provide grid services**: Distributed energy resources have the potential to provide a greater number of services to the distribution utility, such as peak load reductions and volt/VAR support through smart inverters or EV batteries. These services may allow the utility to defer investments that would have otherwise been made to address reliability or system stability issues. In recognition of these capabilities, innovative jurisdictions are placing greater emphasis on non-wires alternatives (NWAs) at the distribution level. Examples include Connecticut, Maine, and New York.

Integrating Electric Vehicles

Electric vehicles (EVs) have incredible potential to assist in the reduction of greenhouse gas emissions and save utilities and ratepayers money. For these reasons, states are becoming increasingly interested in promoting EVs and managing EVs to provide grid services, such as demand response. California leads the country in such investments, as the three major IOUs in the state are engaged in commission-approved EV infrastructure initiatives. For example, San Diego Gas & Electric plans to install 3,500 private charging stations at apartments, condominiums, and businesses, including disadvantaged communities. Pacific Gas & Electric has deployed a Direct Current Fast Charger Micro-Siting Tool, a mapping tool which assists in the identification of potential sites for fast chargers within the utility's service area. Southern California Edison has proposed an electric transit bus make-ready program, and a program to install fast chargers in high-density areas.

Utilities are increasingly exploring managed EV charging as a form of demand response. Managed charging uses a combination of infrastructure and communication signals to control the energy consumed by an EV according to grid needs. Examples include a pilot run by Pepco Maryland and Pacific Gas & Electric's "ChargeForward" program.

Innovative Rate Designs and Tariffs

Time-varying rates have long been used to encourage customers to reduce consumption when it is most valuable to the system, since reducing peak demand during high-priced hours can reduce wholesale market prices and lower power plant emissions. With the expansion of advanced metering, time-varying rates are becoming more common, particularly for residential customers. They are also being used to better integrate distributed energy resources.

Time-varying rates have been used to provide demand response in Maryland, and to promote the efficient deployment of solar in California. Well-designed time-varying rates are also critical for managing electric vehicle charging load to ensure that EVs do not strain the grid during peak hours, and for encouraging the adoption of EVs.

Innovative tariffs can also help to spur the development of distributed energy resources in beneficial locations. New York is transitioning away from static pricing (e.g., net metering) to dynamic tariffs for distributed energy resources that seek to better capture the timing, location, and performance value associated with the services provided by the resources. These tariffs are referred to as "Value of DER" or "VDER" tariffs, and will capture traditional avoided costs such as energy, capacity, transmission and distribution and environmental values, as well as the locational value of siting the resource in a particular area on the distribution system.

Outcome-Based Incentives

Performance incentive mechanisms (PIMs) are increasingly being embraced to address some of the traditional disincentives to distributed energy resources and to encourage utilities to achieve specific policy goals. Many jurisdictions already have a set of PIMs addressing conventional areas of utility performance (particularly reliability and customer service), but only a few have begun to introduce new measures of utility performance, including the use of distributed energy resources.

New York is currently in the midst of developing two types of performance incentive mechanisms. These proposed PIMs consist of (1) financial incentives for non-wires alternatives, and (2) policy-driven outcome-based incentives, referred to as "Earnings Adjustment Mechanisms."

- A prominent example of PIMs for a non-wires alternative is the Brooklyn Queens Demand Management program, which was proposed by ConEd to defer a new substation and related investments with a lower-cost portfolio relying heavily on distributed energy resources.
- Niagara Mohawk proposed 14 Earnings Adjustment Mechanisms, ranging from system efficiency (peak load reduction, substation load factor, and DER utilization), to customer engagement (including demand response program participation, and the number of customers making purchases or enrolling in programs through the E-Commerce Platform, the Residential Solar Marketplace, and the Company's direct load control programs).

2. MUNICIPALIZATION

A municipal utility or public power utility is a publicly or community-owned and -operated utility. For this report, a community that owns and operates the utility could be a city, county, public utility district, or a state. The municipal utility operates as a division of the local or regional government and is run by elected or appointed government officials who are accountable to the citizens of the community. Municipal utilities can provide water, sewer, trash removal, wholesale telecommunications, natural gas or electric services. This report is focused solely on municipal utilities that provide electric supply and/or distribution services. For brevity, we refer to municipal electric utilities henceforth in this report as “munis.” In this report, the municipalization process is divided into four phases: *investigation* of the requirements, challenges, costs, and benefits of municipalization, *acquisition* of the assets from the incumbent utility, *transition* of all electric utility operations from the incumbent to the muni, and potentially *fruition*, wherein the utility achieves the objectives that motivated municipalization.

It is important to note that munis are not the same as rural electric cooperatives (coops) and the scope of this research and reporting does not include coops. Coops are private, not-for-profit businesses with broader community governance and involvement rather than direct local government involvement. Coops are owned by and are in business for their members or shareholders, with excess revenues typically distributed to these individuals.

History and Local Context

The District of Columbia (Washington DC, the District, or DC) is a densely populated city of 680,000. As the nation’s capital, the federal government has a significant physical presence in the District, as do the myriad of private entities directly related to government activities. Washington DC is also a very popular tourist destination for both Americans and international visitors. Although not subject to the authority of a governor or state legislature, the District of Columbia Home Rule Act is superseded by jurisdiction by the United States Congress in “all cases whatsoever.”[1] As a result, Congress retains the right to review and overturn laws created by the Mayor and thirteen-member Council. Washington DC is one of two cities that has direct authority over a public utility commission.[2] Because the DC suburbs are in the states of Maryland and Virginia, both motor vehicle and mass transportation issues require considerable cooperation. From a governing, managing, and operating perspective, Washington is a remarkably complex operation.

Electric service in DC is provided by the Potomac Electric Power Company (Pepco), an IOU.

To municipalize, the District would need to take over the local assets and operations of Pepco Holdings Inc. (Pepco), the electric utility that serves approximately 273,000 customers in the District and 569,000

[1] “U.S. Constitution, Article 1, Section 8,” accessed September 28, 2017, https://constitutioncenter.org/interactive-constitution.

[2] The District of Columbia Public Service Commission. The other is New Orleans, where the city council holds the authority granted to the Louisiana Public Service Commission in the remainder of Louisiana.

customers in Maryland.[3,4] There have been several noteworthy events related to Pepco DC in the past six years.

- In 2011, the DC Public Service Commission (DC PSC) issued new reliability metric requirements in response to Pepco's reliability performance. These reliability metrics are codified under 59 DCR 8762, 8763.[5]
- In 2014, Pepco and the District developed DC PLUG, a collaborative effort to spend $1 billion over 10 years to underground targeted circuits throughout the District for improved reliability. In this unique arrangement, Pepco was to fund $500 million through debt and equity and the District was to issue $375 million in bonds to fund infrastructure improvements as part of the undergrounding process.[6] On May 17, 2017, Mayor Bowser signed the Electric Company Infrastructure Improvement and Financing Amendment Act of 2017 (D.C. Act 22-56) into law. This made several amendments to the 2014 DC PLUG policy, including using a pay-as-you-go structure rather than bonds issued by the district. In light of the changes in D.C. Act 22-56, the Commission has opened Formal Case No. 1145.
- Exelon Corporation filed a merger petition to acquire Pepco in 2014. The DC PSC ultimately approved the merger in March 2016 in Formal Case 1119, after initially rejecting the merger in Order 17947. As a result, Pepco has become part of the Exelon family of utilities that now includes electric distribution companies in Illinois, Maryland, New Jersey, and Pennsylvania. Pepco was and remains headquartered in Washington, DC, and maintains a CEO office in the District.

Simultaneously, the city has been proactive in setting forth an agenda to become more sustainable. In 2011, Mayor Gray launched Sustainable DC, a planning endeavor that created aggressive sustainability targets for the District to achieve by 2032.[7] The Sustainable DC plan included targets for the District to cut citywide energy use by 50 percent, increase the use of renewable energy to make up 50 percent of the District's energy supply, and reduce outage frequencies to 0–2 events and outage durations to less than 100 minutes per year. Achieving these emission reduction, renewable energy, and reliability targets requires the input and cooperation of the District's electric distribution company.

Reliability concerns, a perceived loss of a local control, and a citywide sustainability policy with aggressive and achievable performance targets for energy savings, supply, and reliability are all reasons other communities have considered municipalization. Municipalization may be a reasonable option if it

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[3] U.S. Energy Information Administration, "Annual Electric Power Industry Report (861 Data File)," accessed September 14, 2017, https://www.eia.gov/electricity/data/eia861/.

[4] Including approximately 56,000 master metered apartment units.

[5] "D.C. Municipal Regulations and D.C. Register - Final Adopted Rule, 15-3603: Reliability Standards," accessed September 14, 2017, http://www.dcregs.dc.gov/Gateway/FinalAdoptionHome.aspx?RuleVersionID=3973137.

[6] The District Department of Transportation will provide an additional $62 to $125 million through infrastructure bonds.

[7] "Sustainable DC," accessed September 14, 2017, http://www.sustainabledc.org/.

can provide (1) management that is responsive to local needs, (2) improved reliability, and (3) greater flexibility and more rapid innovation to meet sustainability goals, all while (4) containing costs.

Overview of the U.S. Electric Municipalization Landscape

According to the U.S. Energy Information Administration's (EIA) most recent Form 861 data, more than 900 electric utilities have ownership structures of "municipal" or "political subdivision."[8]

Municipalization is rare in recent years. Of these 900 munis, 2 percent (18 munis) have completed municipalization since 1990.[9]

In general, municipalization has occurred in small communities. The average investor owned utility (IOU) is nearly 20 times larger than the average muni.[10,11] This is not surprising, as roughly 80 percent of the country's 19,000 incorporated places have fewer than 10,000 people each.[12]

The ease in which communities have successfully municipalized does not appear to be correlated with other community characteristics. Each community and associated muni is unique, with its own set of challenges, opportunities, and experiences. There have not been a sufficient number of successful municipalization efforts in the past quarter-century to draw robust conclusions about indicators of the ease of success. As is common with significant undertakings, the majority of the communities reported that the process took longer and was more challenging than initially expected.

Though somewhat infrequent, limited in terms of geographic scope, and encompassing a relatively small portion of the overall population, the formation of these munis are attracting more and more notice. Their stories are compelling and their drivers and experiences are generating interest in municipalization in jurisdictions across the United States. The widespread and enduring news coverage of the city of Boulder, Colorado's municipalization efforts is a good example. Boulder's work to increase innovation and align utility goals with the city's sustainability goals has kept municipalization in focus for nearly a decade.

Based on these and other factors, Synapse chose four case studies that would provide the most useful and relevant lessons for the District.

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[8] "U.S. Energy Information Administration's Annual Electric Power Industry Report (861 Data File)."

[9] "U.S. Energy Information Administration's Annual Electric Power Industry Report (861 Data File)," accessed September 14, 2017, https://www.eia.gov/electricity/data/eia861/.

[10] Ibid.

[11] The average IOU has 400,000 customers and nearly 10 million annual MWh sales whereas the average muni has approximately 20,000 customers and 500,000 annual MWh sales

[12] John Wonderlich, "The Long Tail of Small American Cities Is Really, Really Long," *Sunlight Foundation*, February 13, 2013, https://sunlightfoundation.com/2013/02/13/the-long-tail-of-small-american-cities-is-really-really-long/.

Scope of the Research Effort

Synapse reviewed the statistics of all municipal electric utilities formed on or after 1990. Approximately half related to municipalization efforts that involved a military installation, a quasi-governmental agency, or had fewer than 1,000 customers. Following a cursory review of the remaining half, Synapse ultimately selected four for detailed review. Synapse's detailed review consisted of a literature review and discussions with employees of four munis. Although several declined to comment, we spoke with one representative of an investor-owned utility. Additionally, we interviewed a representative of a local environmental organization active in its community's municipalization effort.

Four municipal electric utilities were selected for further research and investigation including: Long Island, New York; Winter Park, Florida; Jefferson County, Washington; and Boulder, Colorado.

- Our interest is in examples that are recent and from more populous communities. As many municipalization efforts occurred decades ago and were implemented by communities with fewer than 10,000 customers, there are few examples that meet either of these basic criteria. The municipalizations of Winter Park, Florida and Jefferson County, Washington meet these criteria.
- We include Long Island, New York because it is a unique and particularly interesting example, even though it is not as recent. Long Island Power Authority (LIPA) represents the largest municipalization effort in modern times, both in terms of the size of the service territory and the number of customers served. Unlike many recently formed and long-established munis, LIPA spans several counties both urban and suburban, and has a governing structure influenced by state politicians rather than local officials.
- Finally, we include Boulder, Colorado, as it represents a municipalization effort that is currently in process for a community of considerable size.

We acknowledge that four examples are not a representative sample and as a result we do not attempt to perform any statistical analysis or draw conclusions with any degree of certainty. We simply note similarities and differences in the form of observations and findings. These observations and findings are only with reference to the four examples we studied.

2.1. Case Studies

Long Island Power Authority, New York

Community Statistics

Census Region[13]	Mid Atlantic
Population[14]	2,854,083
Land Area[15]	1,197 sq. mi.
Population Density Characterization[16]	Urban, Suburban
Median Age[17]	41 years
Median Household Income[18]	$94,064

Municipal Utility Statistics[19]

NERC Region[20]	NPCC
Services	Electric only
Ownership	Transmission and Distribution
Governance Structure	Utility Board, Appointed
IOU Service Territory	LILCO
Year Municipalized/Effort Began	1986/1998
Number of Customers[21]	1,119,104
Percent Residential	90
Percent Commercial & Industrial	10
Annual Electric Sales (MWh)[22]	19,925,438
Percent Residential	48
Percent Commercial & Industrial	52

Investigation: It Started with a Near Bankruptcy[23]

Long Island's municipalization started in the mid 1980's with the near bankruptcy of the investor-owned Long Island Lighting Company (LILCO). The company had invested heavily in the Shoreham Nuclear Power Plant, and its cancellation led to extreme financial distress. The wasted investment in Shoreham was increasing rates, but there was interest in keeping LILCO afloat and avoiding default.

The municipalization efforts were led by then Governor Mario Cuomo. There was public support to take over LILCO, but LILCO opposed. The political outcome was the passage of the Long Island Power Authority Act in 1985, which established Long Island Power Authority (LIPA). LIPA was charged with taking over the Shoreham plant and its debts, as well as controlling electricity costs.[24] In 1989, LILCO sold Shoreham to LIPA for $1, and Long Island ratepayers were to bear the estimated $6 billion in Shoreham costs. LILCO continued to provide electricity to Long Island customers much as before, but the debt burden was reduced through public financing via LIPA.

LONG ISLAND

The Long Island Power Authority territory consists of New York's Nassau and Suffolk counties and part of Queens, New York City, including the JFK International Airport.

Key Factors

- Prices
- Reliability
- Prior Utility Relations

The state created LIPA to replace the poorly performing electric company.

Acquisition: Full Takeover

In 1998, customers on Long Island were still experiencing high utility rates. Governor George Pataki led the effort to take over LILCO's entire system. Valued using the original cost less depreciation method at $6.7 billion, the purchase was financed through public bond offerings.[25] The Suffolk County Legislature and others opposed this approach, filing lawsuits to block the state proposal. The new state plan was ultimately approved and LIPA acquired LILCO's electrical transmission and distribution system, becoming the primary supplier of electricity on Long Island. With lower financing costs, customer's experienced reduced rates.[26,27]

A governing board was formed to regulate LIPA, with five members appointed by the governor and four members appointed by the legislature. LIPA was exempt from state public utility regulation. LIPA set its own rates and planned its own investments with the board's direction and approval.

LIPA was the provider of electricity to Long Island customers and owned all the assets. However, LIPA continued contracting with the restructured utility company (that retained many LILCO employees) to manage the system.

Transition: A Series of Contracts

In June 2010, LIPA launched a competitive procurement process for a new management services agreement. After an extensive selection process, LIPA entered into a new 10-year, $3.9 billion utility services management agreement with Public Service Electric and Gas Long Island, LLC (PSEG), a subsidiary of Public Service Enterprise Group Incorporated.

Fruition: Periods of Rest and Evolution

For over a decade, LIPA continued to own the electric system and contract the day-to-day services without major incident. Rates could be considered high, but they remained lower than before, and service was adequate.

In 2012, Hurricane Sandy inflicted substantial damage on Long Island. The hurricane caused extensive power outages and intense criticisms of LIPA's performance. Under the initiative of Governor Andrew Cuomo, the LIPA Reform Act of 2013 was approved by the state legislature. The act reorganized LIPA, placing the day-to-day operations under PSEG. LIPA shifted its focus to financing matters and overseeing

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[25] Suffolk County Electrical Agency, FERC Opinion No. 467, February 17, 2004. Docket No. TX96-4-001. Available at: https://www.ferc.gov/whats-new/comm-meet/021104/E-51.pdf.

[26] Ibid.

[27] Also in 1998, LILCO's remaining assets, including its electrical generating facilities, were merged with Brooklyn Union Gas, creating a new publicly-traded utility corporation called KeySpan Corporation. In October 2007, National Grid purchased KeySpan and legally assumed KeySpan's contracts with LIPA.

the PSEG contract.[28] The role of LIPA itself was reduced, but the Department of Public Service now had an advisory role. The NY Public Service Board was also given an advisory responsibility over LIPA.

As part of the LIPA Reform Act, some of the $7 billion debt from Shoreham, the transmission and distribution acquisition, and later investments was refinanced to lower the carrying costs. For comparison, LIPA's annual revenues are about $3.6 billion.

Since 2013, LIPA customers appear to be experiencing better service with the current management structure. Customer approval has considerably improved, with over 90 percent satisfaction levels. LIPA's rates are no longer the highest in the New York Metro Area.[29]

New York State Municipalization Law[30,31]	
Legal Standing to Form Electric Municipality	To acquire a utility, a municipality must hold a referendum in a regular or special election with the residents of the municipality. The power to oversee the process is granted to the local governing body. The municipality can then acquire and operate a utility within or without its limits.
Valuation Process	The price may be set through negotiations or condemnation proceedings.
Valuation Details	No information for price setting provided.

[28] "LIPA Reform Act," accessed September 28, 2017, http://www3.dps.ny.gov/W/PSCWeb.nsf/All/F2EA85DF4AB658B285257F57006AFCD8.

[29] "LIPA 2017 Budget," accessed September 28, 2017, http://www.lipower.org/pdfs/company/papers/LIPA%202017%20BUDGET%201-6-2017.pdf.

[30] "The American Public Power Association's Survey of State Municipalization Laws," accessed September 28, 2017, https://www-static.bouldercolorado.gov/docs/Survey_of_Municipalization_Laws_-_Duncan_and_Allen__FINAL___00027359_-1-201504271104.pdf.

[31] "N.Y. General Municipal Law 360 – Powers Granted to Municipal Corporations to Establish, Own and Operate Certain Public Utility Services," accessed September 28, 2017, https://www.lawserver.com/law/state/new-york/ny-laws/ny_general_municipal_law_general_municipal_law_360.

Winter Park, Florida

Community Statistics

Census Region[32] .... South Atlantic
Population[33] 30,208
Land Area[34] .... 9 sq. mi.
Population Density Characterization[35] .... Suburban
Median Age[36] .... 43 years
Median Household Income[37] $59,405

Municipal Statistics

NERC Region[38] .... FRCC
Services .... Electric only
Ownership .... Distribution only
Governance Structure .... Utility Board, Appointed
IOU Service Territory .... Progress Energy Florida
Year Municipalized/Effort Began 2005/2001
Number of Customers[39] 14,393
    Percent Residential 83
    Percent Commercial & Industrial 17
Annual Electric Sales (MWh)[40] 435,454
    Percent Residential 44
    Percent Commercial & Industrial 56

Investigation: It Began with Trees[41]

The scheduled expiration and proposed renewal of the city of Winter Park's franchise agreement with its investor-owned utility (IOU), Progress Energy Florida,[42] prompted Winter Park to explore municipalization in 2001. As with previous franchise terms, the agreement had a clause allowing the city an alternative to renewal—the city could buy the infrastructure, including the poles

WINTER PARK

The City of Winter Park is a medium-sized affluent suburb bordering the northeast corner of Orlando. Home to Rollins College, Winter Park has a lively local arts scene and an active community.

Key Factors

- Reliability
- Undergrounding Wires
- Prior Utility Relations

69%

of voters favored municipalization in a 2003 city election.

[32] "Census Regions and Divisions of the United States."

[33] "U.S. Census Bureau, American FactFinder - Community Facts."

[34] "U.S. Census Bureau, 2016 U.S. Gazetteer Files Record Layouts."

[35] Urban: > 10,000 people/km2, Suburban: 100 and 10,000 people/km2, Rural: < 100 peo

[36] "U.S. Census Bureau, 2011-2015 American Community Survey 5-Year Estimates."

[37] Ibid.

[38] "FERC: NERC Regions and Balancing Authorities."

[39] "U.S. Energy Information Administration's Annual Electric Power Industry Report (861 Data File)."

[40] Ibid.

[41] Conversation with Daniel D'Alessandro, Operations Manager of the Winter Park Municipal Electric Utility, August 21, 2017.

[42] Previously Florida Power and Light and now Duke Energy Florida.

and wires that make up the distribution system, and maintain and operate the electric system itself. In 2005, despite a multi-year campaign by the utility to prevent municipalization, the city purchased the distribution system and began to operate it as a muni.

The city's relationship with Florida Power Corporation and, later, Progress Energy seems to have steadily declined over a period of several 30-year franchise agreements. Our research indicated the primary driver of this deteriorating relationship was the perceived poor service reliability in Winter Park relative to neighboring communities. The poor reliability was likely caused, at least in part, by inadequately trimmed trees. While Winter Park is not the only community with large oak trees, the city government and residents place a particularly high value on the shade trees. To preserve the trees, city officials and citizens had strongly resisted any trimming.

The community asked the IOU to underground the electric distribution wires in order to address the reliability problems while circumvent the tree trimming issue altogether. Additionally, undergrounding could improve town aesthetics by eliminating overhead wires. Undergrounding is a substantial undertaking requiring considerable funds and time. Even so, the IOU agreed to underground the wires, provided the city fully covered the costs.

We identified several reasons why the city chose to municipalize instead. These include the following:

- Prioritizing undergrounding over other capital investments: This would enable the undergrounding to happen more quickly.
- Allocating more money to the effort: a municipal utility would have additional money available by accessing lower interest rates and not paying investors a dividend. Once municipalized, the city could direct that savings to capital improvements in the city and more quickly attain its goal of undergrounding.

In addition to improved reliability and the flexibility to use the revenues as they saw fit, the city's residents also valued ownership of the system. By investing in a muni that hires local employees—employees who work exclusively for Winter Park and thus have a vested interest in the city and its people—customer service and responsiveness might also improve.

An arbitration process ultimately determined the purchase price at $42.3 million, ruling on May 29, 2003.[43] With a specific price, and armed with the multi-faceted drivers discussed above, the City Commission set the referendum date for September 9, 2003.[44]

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[43] "City of Winter Park - Electric Utility 10th Anniversary, Presentation," accessed September 26, 2017, https://cityofwinterpark.org/docs/departments/electric-utility/10th-anniversary-presentation-2015-06-01.pdf.

[44] "City of Winter Park - Electric Utility," *City of Winter Park*, accessed September 26, 2017, https://cityofwinterpark.org/departments/electric-utility/.

The IOU responded by dedicating half a million dollars to a political action campaign against municipalization. Progress Energy's campaign against municipalization involved billboards, flyers, direct mail, prime-time radio and television ads, and door-to-door canvassers.[45,46]

The city formed its own political action campaign supporting municipalization with about one-fifth of the funds that the IOU committed. It used these funds to educate and involve the community in the municipalization effort. It also had the benefit of a strong city commission, good attorneys and consultants, and support from pro-municipal associations such as the Florida Municipal Electric Association (FMEA), Florida Municipal Power Agency (FMPA), American Public Power Association (APPA), and other munis. Despite the IOU's efforts to sway voters against municipalization, the city voted 69 percent in support of municipalization in 2003.

Acquisition: A Two-Year Saga

Over the course of the following two years, the city purchased the distribution system from the IOU and the muni began to serve its 15,000 customers in 2005. Winter Park relied on its City Commission to provide oversight, a pre-existing commission that included the mayor and four commissioners. The city also appointed citizens as members of a Utility Advisory Board to hear issues before they are brought to the commission for decision.

Undergrounding was a priority, but it did not begin immediately and will ultimately take two decades to complete. To address reliability issues, the muni resumed tree trimming. With a greater level of oversight by the city and the use of employees with community ties, the tree trimming effort went more smoothly for the muni than it had for the IOU.

Transition: Successfully Building from Scratch

Taking up the management and operations of the muni proved to be an unforeseen challenge. Perhaps because of the adversarial and litigious nature of the separation from the IOU, the flow of information from Progress Energy to the muni was contentious, constrained, and slow. According to our interviews, the muni did not receive adequate information about the IOU's maintenance plans and faced numerous unexpected problems with the infrastructure. Additionally, the municipal electric system's configuration was especially challenging upon separation from Progress; no transmission or distribution lines connected the west side and east side of the city; the two sides were effectively islanded from one another. Under the existing substation and feeder setup, half of the city could easily suffer an outage at any time. The city already had municipal water and wastewater services, including billing and meter reading, assisting in the electric municipal utility transition. Because the muni did not inherit an

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[45] "City of Winter Park - Our Municipalization Story, Presentation to South Daytona," accessed September 26, 2017, http://www.southdaytona.org/egov/documents/1302183733_26702.pdf.

[46] "City of Winter Park - Electric Utility 10th Anniversary, Presentation," accessed September 26, 2017, https://cityofwinterpark.org/docs/departments/electric-utility/10th-anniversary-presentation-2015-06-01.pdf.

operations center during load separation as have other munis, Winter Park had to build its knowledge of operations from the ground up.

Once operational, the muni issued Requests for Proposals for power supply and management of the distribution system. The muni outsourced operations to a California-based utility services firm called ENCO and contracted with a consultant on power supply to gain the necessary knowledge and experience. ENCO set up a division of its business in Winter Park. The muni hired its own Electric Director and relied wholly on ENCO in the early years to operate and maintain the system. Though operations were far from perfect, the muni persevered.

ENCO's operational support grew more expensive over time, so the muni took some of the operations in-house. The muni augmented the management staff with technical staff such as engineers. Linemen followed, but the hiring process was more difficult as linemen were in particularly high demand throughout the region. The muni had difficulty offering compensation and benefits packages that were on par with IOUs, and therefore had difficulty attracting employees. Many of the applicants that considered employment with the muni had accepted severance packages in advance of layoffs from IOUs. While this was a chance occurrence, the timing aligned well with the muni's needs. Some of these employees valued what the muni could provide: economic stability—as employees of the muni were less likely to be laid off—and assurance that they would not be frequently relocated, as happened with the IOU. The muni attracted enough employees to sustain operations. Further, some of those employees from the IOU came with invaluable working knowledge of the now-municipalized Winter Park electric distribution system.

Fruition: Standard Utility Challenges

Today, the muni continues to contract with ENCO to run its call center but otherwise it is successfully running operations using in-house resources. The muni is dedicating $3.5 million per year to undergrounding the wires and expects to complete this project in 2026. As part of the undergrounding process, Winter Park has decided to simultaneously lay a fiber optic network, thereby enabling the city to offer its residents and businesses additional services such as telephone, internet, and cable television. Rates are lower than those faced by customers in the neighboring IOU, saving residents money. The muni has greater flexibility and latitude to support the city than would an IOU, providing the ability to share staff and equipment with other departments and offer incentives to attract new business to the city.

Over the longer term, the muni will face some similar challenges to IOUs. Revenues are declining for the muni due to greater penetration of customer-sited renewable resources and decreased energy use due to energy efficiency within homes and businesses. The muni is considering changing its rate structure to address the issue of declining revenues and to provide low-income rate relief.

Florida State Municipalization Law[47]	
Legal Standing to Form Electric Municipality	The right of a municipality to own and operate electric infrastructure is fundamental to its purpose. In certain cases, municipalities can collaborate with other entities on electric projects. The use of eminent domain is allowed.
Valuation Process	If negotiation fails, the price will be determined in eminent domain proceedings by a jury. The Public Service Commission may also be called upon to determine the price.
Valuation Details	Just compensation is reproduction property cost, less depreciation, plus going concern value and damages to the remaining system.

[47] "The American Public Power Association's Survey of State Municipalization Laws."

Jefferson County, Washington

Community Statistics

Census Region[48]	Pacific
Population[49]	31,139
Land Area[50]	1,804 sq. mi.
Population Density Characterization[51]	Rural
Median Age[52]	56 years
Median Household Income[53]	$49,279

Municipal Statistics

NERC Region[54]	WECC
Services	Electric, Water, and Wastewater
Ownership	Transmission and Distribution
Governance Structure	Utility Board, Elected
IOU Service Territory	Puget Sound Energy
Year Municipalized/Effort Began	2008/2007
Number of Customers[55]	19,247
Percent Residential	88
Percent Commercial & Industrial	12
Annual Electric Sales (MWh)[56]	315,989
Percent Residential	60
Percent Commercial & Industrial	40

JEFFERSON CO.

The Jefferson County Public Utility District service territory encompasses a small easternmost portion of the county, including two cities, Port Townsend and Port Ludlow, and the Jefferson County Airport. The county has the oldest population in Washington state.

Key Factors

- Lower rates
- Local jobs
- Lower emissions

54%

favored municipalization in a 2008 vote.

48 "Census Regions and Divisions of the United States."

49 "U.S. Census Bureau, American FactFinder - Community Facts."

50 "U.S. Census Bureau, 2016 U.S. Gazetteer Files Record Layouts."

51 Urban: > 10,000 people/km2, Suburban: 100 and 10,000 people/km2, Rural: < 100 pe

52 "U.S. Census Bureau, 2011-2015 American Community Survey 5-Year Estimates."

53 Ibid.

54 "FERC: NERC Regions and Balancing Authorities."

55 "U.S. Energy Information Administration's Annual Electric Power Industry Report (861 Data File)."

56 Ibid.

Investigation: Public Utility-Friendly and Better Hydro Access[57,58]

The state of Washington has a long legislative history supporting municipalization. Two pieces of legislation were particularly impactful.[59]

- The first piece of legislation, a 1931 law known as RCW 54, authorized the establishment of public utility districts (PUDs) to "conserve the water and power resources of the State of Washington for the benefit of the people thereof, and to supply public utility service, including water and electricity for all uses".[60] Nearly two dozen PUDs were established over the next eight years, including Jefferson County in 1939. Most of these PUDs remain in existence, though their service offerings expanded over time. Today, most PUDs (24) provide electricity, many (19) provide water or sewer services, and a growing number provide access to broadband telecommunications.
- The second piece of legislation, the 1937 Bonneville Power Act, established the Bonneville Power Administration (BPA) to market the power produced at the federal dams. The act also gave "preference and priority in the use of electric energy to public bodies and cooperatives," including PUDs. Today, many PUDs, including Jefferson County, get all or most of their power from BPA. This access to hydro power helps keep rates low for PUD customers.

A citizens group, driven by the appeal of potentially lower rates and clean hydro power from BPA, encouraged the community to municipalize.[61] Port Townsend showed interest in becoming a muni starting around 1998. Port Townsend tried to municipalize its section of Jefferson County but ran into geographical limitations. Around 2007, Port Townsend encouraged the PUD to take a more active role in municipalization. The PUD investigated municipalization and paid for feasibility studies.

In 2008, Port Townsend collected enough petitions to put the question on the voting ballot. The group campaigned and held meetings to educate the community on the merits of municipalization. The vote narrowly passed with 54 percent in favor of municipalizing.[62,63]

Following the 2008 vote, the PUD started researching its municipalization options and building an acquisition and transition team. The PUD worked with lawyers, engineers, and consultants who had

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[57] Conversation with Jim Parker, Manager of the Jefferson County Public Utility District, August 22, 2017.

[58] Conversation with Gretchen Aliabadi, Manager of Communitcation Initiatives at Puget Sound Energy, August 21, 2017.

[59] "Washington Public Utility Districts Association: History of PUDs in Washington," accessed September 15, 2017, http://www.wpuda.org/pud-history.

[60] The law was amended to include broadband telecommunications service in 2000.

[61] The drivers for municipalization became multifaceted over time. PSE was eventually sold to Macquarie Group, an Australian-owned investment bank. Over time, the community perceived that PSE scaled back its operational presence in Jefferson County and contracted for services rather than hiring local employees. Though this sale occurred after the vote, it motivated the citizens further because they felt they were losing local control of their electricity.

[62] "Jefferson PUD Electric Service Backgrounder," May 3, 2010, http://www.jeffpud.org/wp-content/uploads/2014/04/power_backgrounder.pdf.

[63] Only the eastern side of Jefferson County municipalized during this process. There are three other public utility districts serving the western side of the county, which serve a much smaller population.

previously been involved in the municipalization of other communities. The PUD already provided water and wastewater utility services to Jefferson County, and it would expand those operations to provide electrical services.

Both the PUD and PSE completed feasibility studies, using different evaluation methods. These studies generated different purchase prices for PSE's assets. PSE's study estimated asset costs at more than $100 million,[64] while the PUD's study placed the price between $34.9 million (original cost less depreciation) to $69.8 million (twice original cost less depreciation) with $47.2 million as the assumed cost (a premium over going concern, the appropriate fraction of the amount for which Puget Sound Electric received in selling the entire company to Macquarie).[65]

Acquisition: Negotiation Avoids Condemnation

Between 2008 and 2010, the PUD and PSE negotiated the purchase of PSE's assets and services in Jefferson County. The PUD believed that a condemnation lawsuit[66] may have resulted in a lower purchase price, but it felt that the additional litigation costs—and costs associated with time delays due to several years of appeals—would offset much of the difference. As a result, the PUD decided to negotiate the price with PSE instead of litigating. The PUD also considered that the "condemnation process would have limited the ability of the PUD to take a close look at the conditions of PSE's facilities and review its operation prior to the take-over."[67]

To finance the purchase of PSE's assets, the PUD applied to the Rural Utility Service (RUS), a program stemming from U.S. Department of Agriculture, that offered long-term loans at low interest. The PUD received an interest rate of around 2.7 percent.

Transition: Shared Ownership and Cooperation

As part of the PUD and PSE's negotiations, the parties agreed that until 2013, the PUD would own the electric system, but PSE would run it. During this time, the PUD would pay PSE for capital improvement projects. From 2010 to 2013, the PUD learned how to operate the system.

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[64] "Puget Sound Energy News Release," September 30, 2008, https://pse.com/aboutpse/PseNewsroom/NewsReleases/Pages/Independent-analysis-of-Jefferson-County-PUD-electric-utility-study.aspx.

[65] D Hittle & Associates, Inc., "Final Report: Preliminary Feasibility Study Public Utility District No. 1 of Jefferson County Electric System Acquisition," October 24, 2008, http://www.jeffpud.org/wp-content/uploads/2014/04/JeffPUD-Final-102408.pdf.

[66] A condemnation lawsuit is a judicial proceeding by which a governmental body exercises its right to take property by eminent domain for public use upon the payment of just compensation. Such a proceeding adjudicates all rights, including ownership and just compensation, as well as the right to take the property.

[67] "2012 Jefferson PUD State Audit," accessed September 28, 2017, http://www.jeffpud.org/state-audit-of-jefferson-pud-for-2010-2011-and-2012-is-online/.

The PUD was fortunate in that the assets purchased from PSE included an operations center. The operations center gave the PUD a base from which is could more quickly begin managing and operating its electric system.

Fruition: Insulated from Declining Revenues

The PUD's electrical operations has been in service for nearly five years. The PUD's rates are lower than they were in the past and include reduced rates for low-income customers. In addition, the PUD has an acceptable response to outages and hires local employees and linemen. The PUD also promotes energy efficiency with BPA's assistance, including distributing LED bulbs and heat pump materials at local fairs and events.

Though 300 customers have solar and the market penetration of renewable energy is growing, the PUD's sales are steady due to some recently colder winters and an increase in electricity-intensive marijuana cultivation in the state. As a result, the PUD does not currently face some of the revenue challenges affecting utilities, including other munis.

Washington State Municipalization Law[68]	
Legal Standing to Form Electric Municipality	A municipality must provide an ordinance to be ratified by the majority of voters in the territory. Condemnation proceedings are allowed, unless the municipality is located within a public utility district that owns the electric infrastructure in question.
Valuation Process	The price is determined through negotiations or condemnation proceedings.
Valuation Details	No information for price setting provided.

[68] "The American Public Power Association's Survey of State Municipalization Laws."

Boulder, Colorado

Community Statistics

Census Region[69] .... West
Population[70] 108,090
Land Area[71] .... 25 sq. mi.
Population Density Characterization[72] .... Urban, Suburban
Median Age[73] .... 28 years
Median Household Income[74] $58,484

Municipal Statistics

NERC Region[75] .... WECC
Services .... Electric only
Ownership .... Distribution only
Governance Structure .... Utility Board, Appointed
IOU Service Territory .... Xcel Energy Colorado
Year Municipalized/Effort Began TBD/2011
Estimated Number of Customers[76] 47,095
  Percent Residential 83
  Percent Commercial & Industrial 17
Annual Electric Sales (MWh)[77] 1,396,324
  Percent Residential 19
  Percent Commercial & Industrial 81

Boulder differs from the other case studies because it has not yet municipalized. Therefore, only the investigation phase is included below. Notably, Boulder provides useful insights into different aspects of the investigation phase that are highly relevant to the District, which we have detailed below.

BOULDER

Boulder is near many outdoor recreational sites, attracting environmental advocates and nature enthusiasts. In Boulder, environmental awareness is at the forefront of energy-related policy. Boulder has a strong student presence, a median age under 30, and it is home to a large innovation hub.

Key factors

- Clean energy goals
- Autonomy
- Customer choice

66%

of voters approved an acquisition cap and charter necessary to municipalize.

69 "Census Regions and Divisions of the United States."

70 "U.S. Census Bureau, American FactFinder - Community Facts."

71 "U.S. Census Bureau, 2016 U.S. Gazetteer Files Record Layouts."

72 Urban: > 10,000 people/km2, Suburban: 100 and 10,000 people/km2, Rural: < 100 peo

73 "U.S. Census Bureau, 2011-2015 American Community Survey 5-Year Estimates."

74 Ibid.

75 "FERC: NERC Regions and Balancing Authorities."

76 Robertson-Bryan Inc., "Boulder Municipal Utility Feasibility Study," August 16, 2011, https://www-static.bouldercolorado.gov/docs/Feasibility_Study_and_Addendum_81111_net1-1-201305160947.pdf.

77 Ibid.

Investigation: "A City that Wants to Be a Learning-Laboratory"[78,79]

The City of Boulder has been a national leader in policies and practices to reduce carbon emissions. In 2002, the city adopted a resolution in support of the Kyoto Protocol, the international commitment to reduce greenhouse gases. In 2006, Boulder implemented the nation's first carbon tax.

However, by 2008, despite many efforts to curb carbon emissions, Boulder realized it would not achieve its Kyoto goals. Boulder needed to change its energy sources to get there. This key finding would place continuous strain on Boulder's relationship with its IOU, Xcel Energy. At the time, Xcel's generation mix was very coal-dependent. Further, Xcel was planning to make additional investments in coal-fired generators.[80] Boulder wanted more control over energy decision-making and the ability to innovate quickly. In 2005, the city created a task force to explore municipalization as an option for achieving its environmental goals.[81,82] This task force took the following steps as part of its municipalization investigation:

1) Assess municipalization's feasibility

The task force conducted a feasibility study for the city and engaged community members. This study looked at the resources needed to meet the city's load, the cost to operate these resources, and the future of Xcel. The feasibility study found that a muni would be able to increase renewable energy, reduce greenhouse gases, maintain reliability, and reduce rates for customers. Further, a muni would not be subject to state regulations or pressure from shareholders. As a result, it would have more freedom to make investments that were aligned with the goals and needs of the community. For example, without existing commitments to procure coal, the city could invest in renewable resources.[83] As an additional benefit, the muni would reinvest any excess revenue in Boulder.

However, the feasibility study also noted some uncertainties. The city's debt to acquire Xcel's infrastructure would be paid through rates and could put considerable risk on ratepayers. If the debt became too high, Boulder's ability to innovate could be stifled. There could be some advantages to remaining with Xcel, such as industry knowledge, a preexisting structure, and proven reliability.

The cost estimates were uncertain as well. This was partially due to unknown costs associated with court proceedings and delays and partially because the city had to rely heavily on projections based on

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[78] Conversation with Heather Bailey, Executive Director of Energy Strategy and Electric Utility Development and Jonathan Koehn, Regional Sustainable Coordinator for the City of Boulder, August 22, 2017.

[79] Conversation with Leslie Glustrom of Boulder Clean Energy Action, September 12, 2017.

[80] "2013 Community Guide: Clean Reliable Low-Cost Local Energy - What's Possible?," accessed September 28, 2017, https://www-static.bouldercolorado.gov/docs/Community_Guide_2013-1-201308200923.pdf?_ga=2.117079942.1251149561.1506631485-385966575.1506631485.

[81] "City of Boulder: Energy Future Background," accessed September 28, 2017, https://bouldercolorado.gov/energy-future/background.

[82] "United Nations Framework Convention on Climate Change: Kyoto Protocol," accessed September 28, 2017, http://unfccc.int/kyoto_protocol/items/2830.php.

[83] "2013 Community Guide: Clean Reliable Low-Cost Local Energy - What's Possible?"

historical data. Boulder struggled to gain full access to information about the local infrastructure. Xcel had extensive knowledge of the regional electric system but lacked incentive to assist the city. After a thorough analysis of the feasibility study, the city concluded that the benefits to forming a public utility outweighed the risk.

2) Assess goal achievement options

Boulder's goals include 100 percent renewable electricity by 2030 and 80 percent reduction of 2005 level carbon emissions by 2050, with specific targets for locally-based generation.

Municipalization is one of several means the city has pursued concurrently to achieve this goal. In addition, the city:

- Has and continues to intervene in Public Utility Commission (PUC) proceedings related to rates, demand-side management, the Renewable Energy Standard, and resource planning, specifically encouraging on the IOU's investment efforts to shift investments from coal to renewable resources;
- Pursued (and continues to pursue) legislative options that allow local jurisdictions to pursue energy-related efforts; and
- Appealed to Xcel to be a laboratory for clean energy implementation—this would create a channel for local technology companies to help develop smarter and more efficient energy networks and allow for collaboration in developing and upgrading Boulder's electric infrastructure.

In addition, the city and Xcel Energy have exchanged several settlement proposals over the years in an attempt to find a mutually-agreeable compromise. In the absence of a less costly, simpler-to-implement alternative, Boulder continued to pursue municipalization as an option.

3) Create a municipalization plan

As Boulder's interest in municipalization grew, the city formed a municipalization organization called Energy Future. This organization is a division of city government and is charged with leading the municipalization effort with city staff and community advocacy groups. Using the feasibility study as a guide, the city developed a plan for acquisition, transition, and long-term service, pending PUC approval. Community education was a vital aspect in the plan to municipalize, particularly because Boulder needed voter approval. Energy Future relied heavily on grassroots organizations to advocate for the ballot measures in support of the public utility.

4) Decide to municipalize

The first concrete step to forming a muni came when the city chose not to renew its franchise with Xcel Energy in 2010.

As detailed by Colorado state law, a municipality must discontinue an IOU franchise agreement prior to forming a muni. The city put two measures on the ballot in 2011 that each passed by a slim margin:[84]

- Issue 2B, to increase the utility occupation tax to fund the city's purchase of an existing electric system, and
- Issue 2C, to authorize the city to create a muni.

The city also replaced the franchise fee they paid to Xcel with a city tax that has provided the city's municipalization team with approximately $11 million in funding to date. This funding is being used to cover the cost of feasibility studies, engineering, legal fees, and any other related costs.[85]

The city's most significant expenses have been from delays and regulatory roadblocks. In the last four years, Boulder has been involved in legal proceedings with Xcel at the local and state levels, and courts have ruled both in favor of and against municipalization.

- In 2013, the city council voted that it had met the requirements to demonstrate that it could provide equal or better service to the territory. It further said condemnation proceedings could be filed if a negotiation could not be reached.[86] Voters approved spending up to $214 million to buy the assets necessary to create the utility.[87]
- In 2014, Xcel Energy filed a lawsuit claiming the city had not successfully shown that it could run a utility. The city filed to dismiss the lawsuit. [88]
- In 2015, a district court judge sided with the city and dismissed the lawsuit.[89]
- In 2016, the Colorado Court of Appeals overturned the judge's 2015 decision, saying it still had doubts that the city had proven itself capable of providing equal or better service.
- In 2017, the PUC issued a decision allowing Boulder to proceed with forming a muni, directing Xcel to work with the city to finalize asset transfer. The PUC will require

[84] "New Era Colorado Foundation: We Just Made History!," accessed September 28, 2017, http://neweracolorado.org/2011/11/09/we-just-made-history/#.Wc1hvFtSzX4.

[85] "Energy Future: Budget & Funding," accessed September 29, 2017, https://bouldercolorado.gov/energy-future/budget-funding.

[86] Heather Bailey, "Boulder's Path to Municipalization," May 27, 2015, https://www-static.bouldercolorado.gov/docs/2015.05.27_DC_Presentation_FINAL-1-201507280910.pdf.

[87] Robert Walton, "Colorado Regulators Deny Much of Boulder's Muni Plan," *Utility Dive*, September 18, 2017, http://www.utilitydive.com/news/colorado-regulators-deny-much-of-boulders-muni-plan/505112/.

[88] "Public Service Company of Colorado v. City of Boulder," *FindLaw*, September 22, 2016, http://caselaw.findlaw.com/co-court-of-appeals/1748784.html.

[89] "Boulder Municipalization: A History," *Empower Our Future*, accessed September 29, 2017, http://empowerourfuture.org/boulder-municipalization-a-history/.

Boulder and Xcel to form an agreement on substation configuration and created several conditions for the city to follow. The city is still reviewing the decision.[90]

Despite substantial negotiation and litigation, the city and its IOU have not reached an agreement. Looking back, the city wishes it had met with the PUC as the first step of the process in order to minimize the risk of additional costs and delays from extensive litigation.

On August 29, 2017, the City of Boulder, along with 14 other parties, signed a stipulation filed with the PUC. This stipulation gives the PUC the opportunity to evaluate a Colorado Energy Plan Portfolio during the pending Electric Resource Plan proceeding.[91] The Colorado Energy Plan Portfolio allows for: (1) voluntary retirement of select existing coal-fired generation resources and (2) deployment of cost-effective renewable energy resources with lower carbon dioxide emissions. The President of Xcel Energy Colorado stated, "The proposal could increase renewable energy to 55 percent by 2026, save customers money, and dramatically reduce carbon and other emissions."[92] While this stipulation is not likely to enable Boulder to achieve its 100 percent renewable electricity goal without municipalizing, it represents considerable progress toward Boulder's goal of increasing renewable penetration in the generation mix of the city and state.

Colorado State Municipalization Law[93,94]	
Legal Standing to Form Electric Municipality	A municipality's governing body has the power to acquire electric infrastructure and any accompanying components needed for ownership, operation, and maintenance of the system. A municipality cannot acquire the system until it has been approved at a general or special election. Once authorized, the municipality can engage in negotiations or condemnation proceedings. If a franchise exists, the municipality must wait to condemn at 10 years, 15 years, or any time after 20 years.
Valuation Process	The price may be set through a negotiation with the IOU, or through condemnation proceedings.
Valuation Details	The price of the system can either be set in negotiations, or through condemnation, in which case the system would be sold at fair market value. The municipality is not required to purchase any parts of the system if deemed obsolete or useless.

[90] "City Offers Statement on Public Utilities Commission Written Ruling; Outlines Next Steps in Ongoing Analysis Process," September 14, 2017, https://bouldercolorado.gov/newsroom/city-offers-statement-on-public-utilities-commission-written-ruling-outlines-next-steps-in-ongoing-analysis-process.

[91] Attachment A: Stipulation in the Matter of the Application of Public Service Company of Colorado for Approval of its 2016 Electric Resource Plan, No. 16A-0396E (August 29, 2017).

[92] "Xcel Energy, Other Groups Unveil Colorado Energy Plan," *Business Wire*, August 29, 2017, http://www.businesswire.com/news/home/20170829006165/en/Xcel-Energy-Groups-Unveil-Colorado-Energy-Plan.

[93] "The American Public Power Association's Survey of State Municipalization Laws."

[94] "Colorado Revised Statutes Title 31. Government Municipal § 31-15-707," accessed September 28, 2017, http://codes.findlaw.com/co/title-31-government-municipal/co-rev-st-sect-31-15-707.html.

2.2. Findings

Because there are an insufficient number of examples of municipalization in recent decades to allow for robust numerical comparisons or tests of various municipalization parameters, we are limited to observations based on several anecdotes. We make several key findings based on these anecdotes.

First, a motivating factor for municipalization was when a community's priorities or experiences were different than that of the incumbent utility or the rest of the territory. For example, Long Island had a non-functioning nuclear power plant, poor storm response, and high customer bills. Winter Park perceived that electric reliability in Winter Park was worse there than in surrounding communities and had greater affinity for its oak trees than nearby communities with similar shade trees. Jefferson County was concerned about the loss of local influence when their IOU was purchased by a foreign investment team and began to eliminate local utility jobs. Boulder's culture places a higher regard on environmental stewardship than most communities in Colorado.

Second, there was little consistency between the studied communities. The following list provides further context as to the types of variability we observed:

- State laws governing municipalization varied widely with respect to age, certainty, and extent to which the process was designed to facilitate or hinder municipalization. As state laws can allow for or impede municipalization, we felt it was important to provide additional detail on this finding. We summarize the content of municipalization laws nationwide and the nature of their variability in the section entitled State Municipalization Laws below.

- The sequence of steps in the municipalization process varied from community to community. We provide further detail on this finding in the section entitled Municipalization Process below.

- The level of interaction between the communities and tone of IOUS in response to municipalization ranged greatly. Upon completing due diligence, Jefferson County amicably negotiated a price and terms with the IOU. In doing so, Jefferson County minimized both risk and the legal, accounting, and engineering costs that would have been required by settling through negotiation rather than litigation. Boulder and Xcel Energy vacillated between settlement and litigation throughout the process. Winter Park's entire municipalization process was contentious.

- The interaction with and materials and process required by Public Utility Commissions (PUCs) was inconsistent across communities. In fact, there does not appear to be a framework or guidance used by PUCs to evaluate municipalization requests. A lack of PUC experience combined with the absence of a structure or method for considering municipalization may be contributing to this variability. City of Boulder representatives suggested that meeting with the state PUC early in the process to agree on the steps and information requirements may have shortened the timeline for their municipalization effort.

- The factors that motivated municipalization varied across communities. Common goals included lower rates, increased reliability, local decision-making control, and greater/faster innovation. LIPA's efforts were related to a financial bailout, very high rates, and later, poor storm responsiveness. Winter Park was driven by reliability and the desire to underground wires. A Jefferson County muni would allow access to Bonneville power, allowing for reduced electric supply costs. For Boulder, the carbon intensity of the IOU's supply mix was no longer tolerable.

- Operational preparedness varied widely by muni, and luck played an important role. LIPA's muni transition included retaining much of the incumbent utility's labor pool and knowledge base. Winter Park experienced significant challenges due to a lack of operational preparedness, some of which were offset by its good fortune in system separation and timing. The muni acquired an operations center and hired employees laid off by its IOU. Jefferson County's arrangements with PSE to operate its system for 3 years after ownership transfer and with Bonneville Power on power purchases made for a much smoother transition. Boulder has developed many detailed plans on how to separate the electrical system.

Third, while the initial factors driving municipalization varied across communities, the drivers for municipalization became more complex, multi-faceted, and overlapping over time. Reducing rates and customer service became additional values for LIPA and Winter Park over time. The Jefferson County community came to believe that a locally-owned utility with workers located in-county would result in better service. Boulder's goals broadened from environmental concerns and the desire for innovation to also include lower rates.

Fourth, benefits of municipalization that are more difficult to quantify were often an important factor in a communities' decision to municipalize. Some communities placed a higher value on improved reliability, reduced environmental impact, or more responsive customer service than reduced rates.

Fifth, one of the most significant challenges munis faced was acquiring/building the knowledge base to operate the utility. Experienced personnel with knowledge of the electrical system were critical for a successful transition from the IOU to the municipal utility but were difficult to identify and hire.

Lastly, the potential for innovation is greater for municipal utilities, but not every muni studied has taken advantage of increased flexibility. This may be due to a lack of vision or knowledge of cutting edge options, but on the other hand, a muni's more conservative operations and planning policies may be aligned with the expressed preference of its community.

State Municipalization Laws

The state laws that determine the process of municipalization are typically complex, sometimes inconsistent, and infrequently tested. Therefore, a local government prudently considering municipalization must exert considerable effort reviewing and understanding the requirements and constraints associated with municipalization in its state. To help identify potential considerations associated with state laws, Synapse provides the following summary of our review of an American Public Power Association study of relevant state municipalization laws from 2013.[95]

In general, state laws detail:

1. A local government's right to form a muni, and
2. The process to determine the price of the electric infrastructure.

The way in which state laws address municipalization rights and processes varies tremendously by state. For example, some state laws support the right to municipalize based on the principle that the electric grid is fundamental to the power of local government, while other state laws may not be supportive of the right to municipalize and instead erect hurdles.

Additionally, while most laws regarding municipalization exist at the state level, a thorough review of federal laws is also important.[96] One example of a relevant federal law is the dormant Commerce Clause in the U.S. Constitution. The dormant Commerce Clause, considered "dormant" because it references prohibition, bars states from passing legislation that directly harms other states.[97] This can apply to electric municipalization, as the transfer of electricity over state lines is considered interstate commerce. If customers in other states see unfavorable bill impacts because a local government breaks from a multi-state IOU, the muni may be found to be in violation of the clause. However, if the muni can show that the project provides more public benefit than collateral burden and is not discriminatory in nature, it is not in violation. Additionally, if a state can assert itself as an active market participant, it is not subject to judicial review.[98]

Laws regarding the local government's right to form a muni

The rules regarding a local government's right to municipalize vary considerably among states. The critical differences are:

1. Whether communities have the right to form a muni;
2. Whether condemnation or eminent domain proceedings are permitted;
3. Whether the community needs formal permission from the public to form a muni; and
4. Whether the language of the law provides more detail and if that detail is clear.

We provide more detail on each of these differences, along with specific state examples, in the sections below.

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[95] "The American Public Power Association's Survey of State Municipalization Laws."

[96] For a more comprehensive overview of the history of federal laws that are relevant to municipalization, please see the article from the Environmental Law Department of Lewis and Clark Law School titled "Cities and the Low-Carbon Grid" by Uma Outka, available here: http://elawreview.org/articles/volume-46/cities-and-the-low-carbon-grid/

[97] "Commerce Clause," *Cornell Law School Legal Information Institute*, accessed September 14, 2017, https://www.law.cornell.edu/wex/commerce_clause.

[98] Shelley Ross Saxer, "Eminent Domain, Municipalization, and the Dormant Commerce Clause," *University of California, Davis Law Review* 38 (2004): 1505–62.

The right to municipalize. The legal right for a local government to provide power provides an important check and balance on the authority of an IOU. States either provide an explicit right, provide for allowances, or do not allow the formation of munis.

Municipalization is a right in 43 states. Six states allow for municipalization. One state, Hawaii, does not mention municipalization in its laws (though it is not explicitly prohibited).

The two newest U.S. states, Alaska and Hawaii, have clauses that provide good examples of the two ends of the legal spectrum.

- Alaska allows for a "Declaration of Taking," in which the IOU's title is immediately transferred to the muni upon filing, and details like costs and service transfer are ironed out later.
- Conversely, Hawaii does not give munis any legal standing to acquire IOUs. There are no munis in Hawaii.

The remaining states have legal clauses that fall somewhere in between these two approaches. Several state laws do not describe municipalization as a right, but rather as an allowable option. The following provides two of the more common examples.

- In certain home-rule states such as Delaware or Maryland, the power to form a muni is not governed at the state level but rather the local level; communities within these states must consult their individual charters to learn their rights and restrictions.
- In Mississippi, a community can only municipalize if the Public Service Commission revokes the IOUs Certification of Public Convenience and Necessity. Therefore, the community must convince the Public Service Commission that forming a muni is in the public's best interest.

The allowance of legal proceedings. By allowing these proceedings, the state is defining the municipality's legal right to purchase private infrastructure and operate the electric system, even if the IOU is opposed to selling. Some state laws still require that negotiations take place between the utility and municipality before the initiation of condemnation or eminent domain proceedings, and to use the option only if a compromise cannot be reached. 35 states allow municipalities to use condemnation or eminent domain.

The requirement for public permission. The need to obtain permission from the public to form a muni provides a check on municipalization. However, the form of these laws is important as some laws may be more stringent or burdensome than necessary and present a barrier to municipalization. The public is often defined as an individual, group of individuals, or presiding body representing the public interest. Permission can take the form of either a vote by the citizens in the community, or a decision by authorized parties such as elected officials, the commission or another presiding body, or a third party such as a judge.

Fourteen states require public permission, including:

- Arizona, which requires approval from a simple majority of voters; and
- Nevada, which requires a petition signed by two-thirds of taxpayers.

Eleven states require third-party approval:

- Michigan requires approval from three-fifths of electors.
- In Iowa, a muni can file a petition with the Iowa Utilities Board, but the request may be denied if the board determines it is not in the interest of the public.

The clarity of the law. Laws that are unclear may be misinterpreted or interpreted in ways that unduly inhibit the formation of a muni. Some states add additional detail that may further support the formation of munis. For example:

- New Hampshire states that a municipality can "establish, expand, take, purchase, lease, or otherwise acquire and maintain and operate… one or more suitable plants for the manufacture and distribution of electricity."[99] This level of detail eliminates any ambiguity about the authority of a local government to control its electric system.
- Oregon law dictates, "Any incorporated city may […] condemn for its use private property for the purpose of erecting and maintaining electric lines thereon […] and for the purpose of constructing electrical systems for municipal uses."[100]

On the other hand, some states have additional detail that may hinder the formation of munis. For example:

- Louisiana's law states, "Where a price cannot be agreed upon with the owner, any municipal corporation of Louisiana may expropriate property whenever such a course is determined to be necessary for the public interest by the governing authority of the municipality."[101] This law allows for the formation of a utility, but in interpretable language about what the municipality is required show to prove "public interest."

Laws regarding the process to determine the price of the electric infrastructure

The laws can also differ considerably with respect to the process for determining the price of the electric infrastructure.

[99] "2013 New Hampshire Revised Statutes: Title III - Towns, Cities, Village Districts, and Unincorporated Places, Chapter 38, Section 2, Municipal Electric, Gas or Water Systems," *Justia Law*, accessed September 29, 2017, http://law.justia.com/codes/new-hampshire/2013/title-iii/chapter-38.

[100] "Oregon Revised Statutes (ORS), 2015 Edition, Chapter 223, Section 005," accessed September 29, 2017, https://www.oregonlegislature.gov/bills_laws/ors/ors223.html.

[101] "2012 Louisiana Laws, Revised Statutes, Title 19, Expropriation by Municipal Corporations, Chapter 19, Section 102," *Justia Law*, accessed September 29, 2017, http://law.justia.com/codes/louisiana/2012/rs/title19/rs19-102.

The typical process appears to be agreement between the IOU and the community on a fair price. Both parties are motivated to negotiate to minimize or avoid the legal fees and extended delays associated with court proceedings. If negotiations fail, laws typically dictate one of three options for determining a price:

1. The price is decided per eminent domain or condemnation procedure;
2. The public utility commission decides; or
3. The public decides either by jury or vote.

However, exceptions exist.

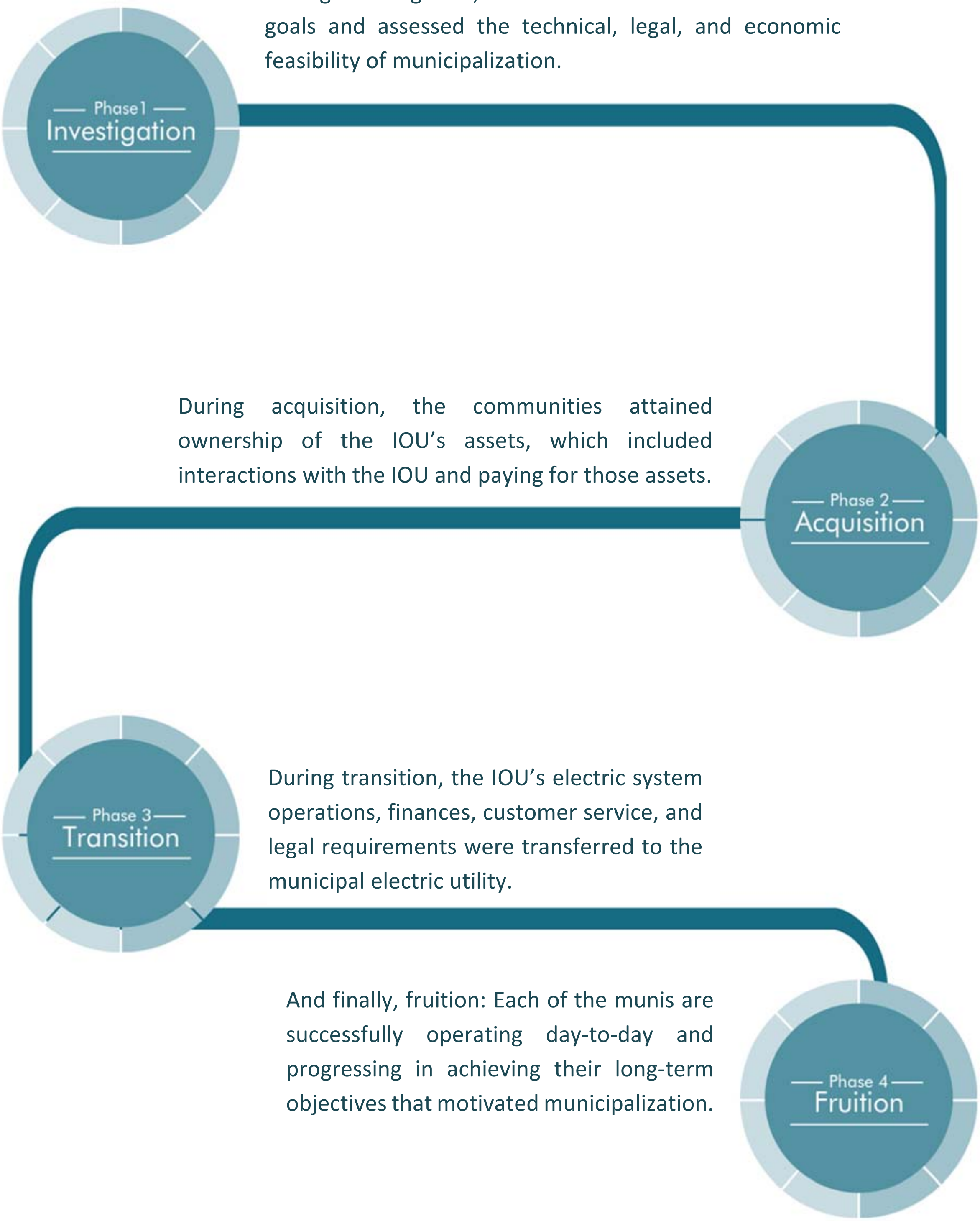
- For example, in Kansas, when a community files a resolution to form a muni, the district court of the county selects a 3-person committee with a commissioner from the community, the IOU, and an expert engineer. This committee determines a fair system price.

- In Pennsylvania, the rules for determining price vary city to city, depending on the size and population.

Legal guidance on what should be factored into the system price typically offers little detail, and in many cases, is omitted entirely. Variations include whether to account for factors such as depreciation, lost revenue, damages, severance, stranded costs, intangible assets, or franchise costs. Also, several states specify that the muni is only required to purchase the portions of the system that it wishes to acquire.

2.3. Municipalization Process for the Studied Communities

Each of the communities we studied progressed through four phases as they considered and ultimately formed municipal utilities.



During investigation, the communities identified their goals and assessed the technical, legal, and economic feasibility of municipalization.

During acquisition, the communities attained ownership of the IOU's assets, which included interactions with the IOU and paying for those assets.

During transition, the IOU's electric system operations, finances, customer service, and legal requirements were transferred to the municipal electric utility.

And finally, fruition: Each of the munis are successfully operating day-to-day and progressing in achieving their long-term objectives that motivated municipalization.

Table 1 provides a summary that compiles the phases, steps, and questions that the observed communities sought to answer during the process. It is important to note that each community experienced a unique municipalization process, and the sequencing of the steps the communities took varied. Communities asked some questions repeatedly throughout the process, and found the answers evolved over time.

Table 1. Compilation of questions asked by case study communities

Phase	Steps	Questions
INVESTIGATION	**Identify goals**	What goal(s) are we trying to achieve?
		What issue(s) are we trying to resolve? What is causing those issues?
	Assess goal achievement options	Will municipalization achieve our goals?
		Are there methods besides municipalization through which we could achieve our goals?
		Have we discussed our goals with the Investor Owned Utility (IOU)? Are there barriers that prevent the IOU from helping us achieve our goals? Can those barriers be addressed?
	Assess municipalization feasibility	What are our costs to municipalize, including those related to study and negotiation and those related to the purchasing of IOU and other infrastructure?
		What financing options are available to us to pay for the IOU's assets? What are the advantages and disadvantages for each of those options?
		What do we perceive as key benefits from municipalization? Can we realize these benefits? Can we quantify these benefits?
		Will municipalization benefit our citizens? Will some community members be disadvantaged by municipalization?
		What are our legal and regulatory rights, obligations, and processes required for municipalization? Can we implement the requirements in a reasonable timeframe?
		What acquisition options are available to us to transfer ownership from the IOU? What are the advantages and disadvantages for each of those options?
		Are there other nearby communities that have municipalized? If so, have we discussed municipalization with these communities?
		Do our citizens support municipalization?
		How will we educate our citizens about municipalization and the municipalization process? How will we continue to educate our citizens throughout the municipalization process?
		Who will lead the municipalization effort?
		Do we need industry experts or partners to succeed? If so, who?
	Decide to municipalize	Do the benefits, including those that are difficult to quantify, outweigh the costs?
		Are we prepared for the municipalization process?
		Are we prepared to operate an electric utility?

Phase	Steps	Questions
ACQUISITION	Engage with the IOU	What is the status of our relationship with our IOU? Can we cooperate?
		How will we address any opposition from the IOU?
	Acquire the IOU's assets	What strategy will we use to acquire the IOU's assets?
		What is the legal and regulatory process we will go through to acquire the IOU and to form a municipal electric utility? Are we prepared for that process?
		Do we need citizens to vote in favor of municipalization in order to proceed?
		Is there a timeframe in which it would be more advantageous for the community to municipalize (i.e., franchise renewal, lower cost to borrow, greater availability of technical resources)?
	Pay for the IOU's assets	Did the results of our feasibility study favor municipalization?
		Have we valued the IOU's assets? What will it cost us to purchase the IOU's assets?
		What approach will we use to pay for the IOU's assets?
		How will we negotiate with the IOU? Who will be part of the negotiations?
TRANSITION	Operate the electric system	How will our muni provide electricity generation, transmission, distribution, and customer services to customers?
		Will our muni purchase power from a market? Will it be wheeled across the IOU’s lines? Will our muni need to own or operate generation resources?
		What is the IOU’s maintenance plan for the current system? Are those plans implementable by our muni?
		Will we be able to hire the technical resources and acquire the knowledge (i.e., linemen) to operate the electric system?
	Manage the municipal electric utility	Will the IOU be involved in the transition process? What are the IOU's roles and responsibilities? Is there a timeline and plan to phase out the IOU?
		Will we hire consultants to manage and operate the municipal utility?
		Are there groups of customers within our community that currently receive special treatment from the IOU, such as industrial or low-income customers? Will our muni replicate those practices?
		Will we be able to hire personnel who can manage and operate our muni?
		Does the IOU provide tax or other revenue to the community? Will our muni retain that practice in the form of payments in-lieu of taxes (PILOTs) or other payments?
		Are we prepared to manage the operating budget associated with our muni?
		Are we aware of all operation, maintenance, overhead, and other costs required to operate our muni?
		Will we receive enough revenue from electric rates to cover the costs?
FRUITION	Establish and assess oversight	Is there a robust, non-cumbersome oversight process for our munis operations, management, and finances?
		Once established, is the oversight process working? Is there a process to make amendments?
	Assess finances	Are rates just and reasonable?

Phase	Steps	Questions
		Are Bonbright's principles for rate design being met?[102,103]
		Are costs prudently incurred?
		Is the muni operating efficiently and effectively?
	Assess operations	Is electricity provided consistently and reliably?
		Is our muni adequately prepared for severe weather events?
		Does our muni have a long-term operation and maintenance plan for the electric system?
	Assess management	Are customers being educated about their electricity service and the options available to them?
		Are customers satisfied with their electric service?
	Assess goal achievement	Is our muni achieving the community's previously stated goals?
		Have new goals emerged during the acquisition and transition phases? Are those new goals being achieved?
		Are customers' needs being fully considered and addressed by the municipal utility?
	Innovate	Is the muni adapting to changing customer, industry, and environmental requirements? Is it doing so in a reasonable timeframe?
		Is there more the muni can do to satisfy customers' interests in renewable energy, electric vehicles, storage, energy efficiency, or other demand and supply side resources?
		How can the muni better serve its customers and community?

We provide more detail below on the observed areas of community focus within each phase:

1. **Investigation:** During investigation, the communities identified their goals and assessed the technical, legal, and economic feasibility of municipalization. In this phase, all communities provided community education, conducted feasibility studies and held votes or referendums. These elements helped the communities determine whether to proceed with municipalization. Boulder appeared to be the only community that actively evaluated and pursued alternatives to municipalization during this phase.

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[102] James C. Bonbright, "Principles of Public Utility Rates (2005 Reprint by Powell Goldstein LLP)" (Columbia University Press, 1961), http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

[103] In the seminal work Principles of Public Utility Rates (1961), Professor James Bonbright discusses eight key criteria for a sound rate structure. These criteria are as follows: (1) The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application; (2) Freedom from controversies as to proper interpretation; (3) Effectiveness in yielding total revenue requirements under the fair-return standard; (4) Revenue stability from year to year; (5) Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers; (6) Fairness of the specific rates in the apportionment of total costs of service among the different customers; (7) Avoidance of "undue discrimination" in rate relationships; (8) Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use: (a) in the control of the total amounts of service supplied by the company, and (b) in the control of the relative uses of alternative types of service.

2. **Acquisition:** During acquisition, the communities attained ownership of the IOU's assets, which included interactions with the IOU and paying for those assets. Costs and financing were a large component of the acquisition process. Through extensive, focused, costly, and often protracted feasibility studies and asset valuations, the communities gained a better understanding of the specific resources it would acquire and the cost of those resources. There are different methods for valuing assets, and key assumptions such as depreciation and/or replacement costs were sources of disagreement in some cases, significantly influencing the price. All communities studied engaged in some negotiation, with varying levels of success.

   The approaches used in valuing a system included:[104,105]

   - Original cost less depreciation (OCLD), wherein the price of each asset obtained by the municipality is the undepreciated balance of that asset. Because the undepreciated plant balance is a fundamental component of ratemaking, this value is typically readily available.

   - Going concern, where the book value of the assets is no longer considered, but rather the present value of the future earnings of the utility were it to be sold to a profit-seeking entity.

   - Negotiation, wherein both the IOU and the community relied on valuation metrics such as OCLD and going concern to determine a sales price that included not just the assets but several services provided by the IOU to the newly formed muni while in the transition phase.

   - Arbitration, wherein a third party reviewed the valuations and claims of both parties and determined a final price after weighing the evidence presented.

   OCLD and going concern were employed by Long Island, Winter Park, and Jefferson County. In the latter two cases, the final price was determined through arbitration and negotiation, respectively, rather than by using a single valuation methodology. Communities ultimately obtained the assets through condemnation, direct negotiations with the IOU, litigation, state legislation, or a combination of these options. Communities financed the acquisition costs by issuing bonds or, in the case of Jefferson County, obtaining a federal loan.

3. **Transition:** During transition, the IOU's electric system operations, finances, customer service, and legal requirements were transferred to the muni. Munis needed to deal with:

   - Sourcing electricity generation: Long Island, a community in a deregulated area, purchased power from its regional power market. The communities in vertically

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[104] Filsinger Energy Partners, Inc., "Evaluation of Alternative Ownership Options for Electric Utility Assets on the Islands of Oahu and Hawaii," April 2016.

[105] Florida Public Service Commission Division of Policy Analysis & Intergovernmental Liaison, "Replacement Cost Method of Valuing Utility Generation Assets," March 2001. Available at: http://www.psc.state.fl.us/Files/PDF/Publications/Reports/Electricgas/replcost.pdf

integrated areas, Winter Park and Jefferson County, entered into power purchase agreements with generation suppliers as well as contracts with the IOU to wheel power over the IOU's distribution network.

- Creating a distribution system: Munis separated their electric system from the IOUs surrounding network but found that some form of integration was still necessary, because generation was located out of the muni's service territory and it was necessary to wheel power to serve load.
- Maintaining the distribution system: Communities experienced immediate maintenance requirements that were not known prior to municipalization and had to find solutions to these issues right away.

Munis also learned how to manage and operate a utility in the transition phase. They dealt with:

- IOU involvement: In Long Island and Jefferson County, the IOU continued operating and managing with the muni. Conversely, in Winter Park, the IOU did not engage or otherwise assist the muni during the transition.
- Staff Resources: Munis required personnel with management, finance, and customer service experience to ensure successful operations. Communities providing water or other municipal utility services could leverage internal resources, systems and knowledge. In communities that did not offer other municipal services, the muni often hired consultants or new personnel to provide these services or contracted with the IOU. Some communities that hired IOU or consultants for the initial transition replaced these outsourced positions with permanent internal positions over time.
- Finances: Munis had to manage a sizeable budget, potentially two or three times larger than the budget the community managed prior to becoming a muni. The Winter Park muni and Jefferson County PUD worked to ensure that electricity rates covered the muni's expenses and that revenue and expenses balanced out over the longer term; LIPA was self-contained from the outset.

4. **Fruition:** Now in the fruition phase, the munis studied successfully operate day-to-day and are progressing in achieving the long-term objectives that motivated municipalization. No community we assessed has completely achieved their goals.

2.4. Costs and Benefits

The cost of municipalization is a key consideration for many communities. Most of the costs of municipalization are to acquire the electric system assets or build their own system, although the costs to operate the system and purchase power are significant as well.

A community can consider building its own system if it finds it less costly to build a new system than to purchase the system from the IOU. This prospect is typically unattractive, however, for two reasons. From a financial perspective, paying the full, nondepreciated price for the entire system at once presents a significant sticker shock; replacing worn out components of the system piecemeal spreads the capital costs (and labor requirements) across many years for a far smoother outcome. From a physical infrastructure standpoint, this approach would require building a second set of poles, wires, transformers, and electric meters, because the community is unwilling to go without electricity for the months or years construction from scratch would require. For these reasons, it is typically preferred to purchase the already-built utility assets. Regardless of whether a community buys or builds the electric system, all communities borrow to pay for these assets. The cost is not incurred upfront or all at once.

There are reasons why operating and maintaining a muni can lower cost. While both IOUs and munis borrow money to pay for capital expenditures, municipal bonds typically have lower interest rates than IOU bonds, resulting in lower costs. Unlike IOUs, munis do not pay dividends to investors, further reducing costs. Finally, although munis often pay local taxes or make payments in lieu of taxes (PILOTs), they are exempt from federal taxes. Lower costs can be passed on to customers in the form of lower rates.

On the other hand, munis face challenges that can result in higher costs. Acquisition costs can drive rates upward; according to expert Jim Lazar, "most public power takeovers are in the vicinity of 140% of book value."[106] IOUs, being larger, often have economies of scale that can lead to lower legal, management, and acquisition costs per MWh sold. Munis are frequently not closely monitored by a public service commission, and inadequate auditing can allow poor decisions to multiply. Finally, IOUs have a single, focused objective: safe, reliable power at least cost. Munis, on the other hand, have the flexibility to pursue other goals, and where leadership isn't consistent and wise, that can result in erratic decision making or the refusal to make a decision due to political concerns.

The decision to municipalize requires tough choices about the best use of public funds. All communities have priorities that compete for funds dedicated to improving infrastructure, including refurbishing or rebuilding schools, repairing roadways, and renovating public parks and recreation areas.

In addition to the price tag, communities considering municipalization also evaluate cost effectiveness. Cost effectiveness is a comparison of costs *and* benefits. As is often the case with other public infrastructure projects, the difficult to quantify benefits associated with public electric utilities are frequently key drivers. As many of the benefits are difficult to quantify and may not be experienced in the form of reduced electric rates, each community must decide how much value to attribute to each benefit, in order to make a more informed decision about whether to proceed with municipalization.

Our research brought to light several cost and benefit categories, as well as the price the muni ratepayers ultimately paid for the muni to acquire the IOU's assets.

[106] Herman K. Trabish, "IOU, co-op or muni? Experts debate the creation of public utilities," September 16, 2015. Utility Dive.

Overview of Types of Costs and Benefits

The following table depicts the costs and benefits that communities considered and the extent to which the value of each cost and benefit is quantified. It is important to note that costs are more often quantified than benefits.

Table 2. Potential costs and benefits of municipalization

Costs	Benefits
More Often Quantified	
Assets	Lower Costs/Rates
Customer Education	
Feasibility Studies	
Operational Start Up	
Maintenance	
Power Purchases	
Legal Representation/Litigation	
Less Often Quantified	
Staff Resources	Improved Reliability
	Improved Infrastructure
	Improved Customer Service and Responsiveness
	Environmental Improvement
	More Control over Decision-Making
	Economic Development
	Efficiencies from Inter-Departmental Coordination and Assistance

As mentioned above, costs include the costs to buy or build the electric system as well as the cost to operate the system and purchase the power. However, there are several additional costs like customer education, feasibility studies, and operational start-up costs that communities considered.

The cost of feasibility studies was largely driven by the scope. In the communities we researched, the scope included: a review of the condition of the assets and property value, consideration of potential options and costs associated with severance (the separation of the system), an assessment of capital, operation and power supply costs including an assessment of methods for valuing the capital costs, legal requirements and an analysis of benefits. Boulder, Colorado has spent approximately $11.4 million thus far in its municipalization effort, the majority of which "to cover legal, engineering, and other costs associated with the exploration of municipalization."[107]

[107] City of Boulder Colorado, "Energy Future Budget & Funding FAQ." Accessed September 29, 2017. Available at: https://bouldercolorado.gov/energy-future/budget-funding

There are many potential benefits of municipalization and some are more valuable or relevant to some communities than others. The communities we studied seemed to place a higher value on improved reliability, improved infrastructure, improved customer service and responsiveness, environmental improvement, innovation and greater control over decision-making. However, there are other benefits that were raised.

- Economic development benefits occur when munis promote economic development in their community by offering special rates or discounted connection fees for large customers or new businesses.
- Efficiencies from inter-departmental coordination and assistance can include electric repair or maintenance assistance, general repair or maintenance assistance, technical expertise and leadership, free building space, and sharing of vehicles and equipment.

Comparison of Municipalization Asset Valuations[108]

Caution must be taken when comparing the asset valuations of electric distribution infrastructure for communities with varying geographical size, population density, climate, and other key factors. These factors have significant influence on the physical infrastructure installed, the age of that infrastructure, and its suitability to continue providing utility to the electric system. Furthermore, the legal and political process through which an ultimate price is determined has considerable variation – the same physical system could ultimately be purchased by a municipality for a variety of prices depending on state law and the negotiating ability of the municipality and the IOU.

Table 3 compares the actual asset valuations from several electric municipalization efforts, including Long Island, Winter Park, and Jefferson County to the estimated valuation of Boulder. Note that within the three completed municipalization efforts studied, the inflation-adjusted valuation per customer ranges from $3,800 to $8,500 per customer, and from $125 to $475 per MWh sold. The range is considerable, not applicable to potential municipalization efforts in other communities, and it isn't clear to what extent the range is a function of the variety of physical equipment or the legal and political decision-making involved. Note too that every municipalization effort includes a different bundle of equipment – while all acquisitions include distribution system equipment (wires, poles, transformers) and the on-site electric meters, the inclusion or exclusion of rolling stock, inventory, tools, office space, a control room, billing and accounting software, transmission wires, and electric generation equipment varies considerably and can have a considerable impact on the reported total price of acquisition. Finally, these prices reflect the dollars paid to the IOU, but do not include the costs the municipality faced prior to the purchase – the legal, accounting, and engineering services necessary to protect the municipality's interest throughout the process.

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[108] "Selected Bibliography of Municipal Ownership Feasibility Studies" (American Public Power Association), accessed September 29, 2017, http://appanet.files.cms-plus.com/PDFs/Bib_of_Feasibility_Studies_7-15-16.pdf.

Table 3. Comparison of asset valuations for recently municipalized utilities

	Long Island	Winter Park	Jefferson County	Boulder
Source	actual	actual	actual	estimated
Valuation Components	transmission, distribution + stranded costs	distribution + stranded costs	transmission + distribution costs	distribution costs
Asset Valuation (nominal $)	$6,700,000,000[109]	$42,300,000[110]	$103,000,000[111]	$223,000,000[112]
Assumed Year Dollars	1998	2003	2010	2011
Year Dollar Conversion Factors [113]	1.41	1.28	1.10	1.08
Asset Valuation (2016 $)	$9,457,237,600	$54,337,565	$113,371,585	$240,489,667
Customers	1,119,104[114]	14,393[115]	19,247[116]	47,095[117]
Sales (MWh)	19,925,438[118]	435,454[119]	315,989[120]	1,396,324[121]
Valuation per Customer (2016$)	$8,451	$3,775	$5,890	$5,106
Valuation per MWh (2016$)	$475	$125	$359	$172

109 "Public Authorities by the Numbers: Long Island Power Authority."

110 "City of Winter Park - Our Municipalization Story, Presentation to South Daytona."

111 "Jefferson PUD Electric Service Backgrounder."

112 Inc., "Boulder Municipal Utility Feasibility Study."

113 U.S. Bureau of Economic Analysis, "Gross Domestic Product: Chain-Type Price Index," *FRED, Federal Reserve Bank of St. Louis*, January 1, 1947, https://fred.stlouisfed.org/series/GDPCTPI.

114 "U.S. Energy Information Administration's Annual Electric Power Industry Report (861 Data File)."

115 Ibid.

116 Ibid.

117 Inc., "Boulder Municipal Utility Feasibility Study."

118 "U.S. Energy Information Administration's Annual Electric Power Industry Report (861 Data File)."

119 Ibid.

120 Ibid.

121 Inc., "Boulder Municipal Utility Feasibility Study."

Although LILCO sold its debt to LIPA years earlier, it wasn't until 1998 that LIPA purchased LILCO's transmission and distribution system. The value, $6.7 billion, was determined using the original cost less depreciation method.[122]

The value of Winter Park's assets was set at $42.3 million through an arbitration award in May 2003. In 2001, the community hired Black and Veatch to conduct a feasibility study. This feasibility study valued the distribution assets at between $15.8 and $50.3 million. Progress Energy Florida conducted its own valuation and proposed a purchase price of $106 million.[123]

The methodology to determine the purchase price of Jefferson County PUD was negotiation, "over a cup of coffee," wherein both sides proposed values based on several methodologies.[124] The final price, determined in confidential negotiations, also included several other conditions and expectations laid out in the purchase and sale agreement, including Jefferson County's contracting with the IOU to assist with the transition and their ability to return the utility equipment to the IOU within three years should PUD operation of the distribution system prove problematic.

[122] Suffolk County Electrical Agency, FERC Opinion No. 467, February 17, 2004. Docket No. TX96-4-001. Available at: https://www.ferc.gov/whats-new/comm-meet/021104/E-51.pdf.

[123] "City of Winter Park - Our Municipalization Story, Presentation to South Daytona."

[124] Jefferson County Public Utility District, "Jefferson PUD Electric Service Backgrounder," May 3, 2010. Available at: http://www.jeffpud.org/wp-content/uploads/2014/04/power_backgrounder.pdf.

3. SURVEY OF INNOVATIVE UTILITY PRACTICES

The utility industry is witnessing an upsurge in innovative practices related to utility regulation, rate design, and electricity services. New technologies, such as energy storage, distributed generation, and electric vehicles are changing the role of customers from passive consumers of energy to active participants in the grid. These technologies have the potential to respond better to customer demands, enable a more efficient grid, and a cleaner, more affordable electricity system, but only if utilities take an active role in harnessing, managing, and supporting the use of these technologies.

Examples of technologies that are transforming the role of distribution utilities include:

- Distributed generation (such as rooftop solar photovoltaics)
- Distributed storage
- Electric vehicles
- Sophisticated forms of demand response
- Advanced metering infrastructure (and the time-varying rates enabled by the meters)
- Energy control devices (including advanced building energy management systems and smart inverters)
- Advanced utility system communication and controls

In response to the proliferation of these technologies, forward-looking jurisdictions across the country are undertaking a range of innovative activities. This report explores several of these activities:

1. New approaches to distribution system planning and management
2. Efforts to integrate and manage electric vehicles,
3. Innovative rate designs and methods for valuing distributed energy resources, and
4. A shift toward outcome-based utility regulation.

In some states legislatures and regulators have explicitly directed utilities and other stakeholders to proactively consider ways to address these issues. In other states, these issues are arising as utilities propose new ratemaking mechanisms or new types of rate designs that have important implications for distributed energy resources and customers' ability to control their consumption patterns. All states should be attuned to the important policy developments defining the future of this industry.

3.1. Approaches to Planning and Operation

Integration of large quantities of distributed energy resources (DERs) poses a new set of engineering and operational challenges for utilities. Innovative utilities are not only embracing these challenges, but are also actively exploring how DER resources can best serve as a resource for the grid. To effectively utilize DERs, utilities must conduct distribution system planning in a robust and transparent manner, engage with third party DER providers in new ways, and encourage DERs to be developed in locations where they provide the most value.

Distribution System Planning

Different approaches to distribution system planning and control are required to plan for increasing penetrations of electric vehicles, dispatch flexible-demand resources, manage two-way reversible power flows from distributed generation and storage, and strategically deploy distributed energy resources in the most beneficial locations. As illustrative examples, below we describe the distribution system planning practices of California and New York.

California

In 2013, the California legislature passed a bill that requires California's investor-owned electric utilities to file distribution resources plans (DRPs).[125] The law set out to shift the focus of utility planning from planning primarily to meet load growth to planning for integrating cost-effective DERs into the distribution grid with the goal of reducing system costs and helping achieve the state's greenhouse gas emissions targets. Specifically, Section 769 of the Public Utilities Code requires that the utilities' DRPs identify optimal locations for deployment of distributed energy resources[126] and that the utilities:

1) Evaluate locational benefits and costs of DERs on the distribution system,
2) Propose or identify tariffs, contracts, or other mechanisms for the deployment of cost-effective DERs,
3) Propose cost-effective methods of coordinating programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of DERs,
4) Identify any additional utility spending necessary to integrate cost-effective DERs, and
5) Identify barriers to the deployment of DERs such as safety standards and operational needs for reliability.

In addition, the California Public Utilities Commission (CPUC) established three parallel goals for the distribution planning process:

1) to modernize the electric distribution system to accommodate two-way flows of energy and energy services throughout the IOUs' networks;
2) to enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost-efficient manner; and

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125 AB 327 added Section 769 to the California Public Utilities Code.

126 Also referred to as "distributed resources," in California. These include renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

3) to animate opportunities for DERs to realize benefits through the provision of grid services.[127]

To reach these goals, California determined that the new distribution planning process should not be a one-time endeavor, but rather should be conducted on a biennial basis to ensure that DERs become more fully integrated into the IOUs' planning, operations, and investments.[128]

The integration capacity and locational value analysis is a key component of the utilities' distribution resources plans. The three analytical frameworks that comprise this analysis are summarized in the figure below.[129]

Integration Capacity Analysis	Locational Benefits	DER Growth Projections
• The integration capacity analysis involves determining the maximum amount of DER per section of line subject to thermal, voltage, and protection limits. • The results of this analysis are published via online maps that are available to the public.	• Quantification of locational benefits depends on the system need (e.g. voltage support) and the system capacity available to accommodate DER. • Benefits are estimated based on the potential for deferring or avoiding capital project(s), the cost effectiveness of investments to support DER, and whether these investments would benefit both customers and DER.	• Each utility's DRP incorporates three DER growth scenarios using the California Energy Commission's Integrated Energy Policy Report trajectory case and two assessments for high and very high DER growth, distributed across the territory by the type of resource. • Forecasts of peak demand and growth of DERs are 10 year (2016–2025) projections.

Six utilities filed DRPs in July 2015. Below we briefly describe the integration capacity and locational value analysis in San Diego Gas and Electric's (SDG&E) DRP.

[127] CPUC, "Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning," R.14-08-013, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769., August 14, 2014.

[128] California Public Utilities Commission, "Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 - Distribution Resource Planning," Rulemaking 14-08-013, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, February 6, 2015.

[129] San Diego Gas & Electric, "Distribution Resources Plan OIR," August 5, 2015, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5159.

The integration capacity analysis determines the DER capacity that can be installed on a distribution circuit without requiring significant distribution upgrades. To conduct the analysis, each circuit is modeled down to the service transformer using smart meter data. Each circuit is then divided into zones, and the addition of generation is simulated until thermal limits, voltage limits, or protection limits are exceeded. The analysis accounts for load profiles, distributed generation profiles, and specific circuit capacity data. SDG&E uses the Synergi power flow model to conduct its analysis. As of August 2015, SDG&E's integration capacity analysis identified 618 MW of available capacity on the distribution system with the expectation that more capacity would be identified as additional modeling is performed.[130]

A second component of the DRP is the quantification of locational benefits. The utility's methodology for determining locational values incorporates avoided capital and operating expenditures for distribution voltage, power quality, reliability and resiliency. Also included in the locational value are avoided transmission, sub-transmission, substation, and feeder capital and operating costs, as well as values for energy, losses, ancillary services, societal avoided costs, and avoided Renewable Portfolio Standard compliance costs.[131]

The SDG&E's initial forecasts of DER capacity growth were made on a system-wide level, allocated to substations, and then to individual circuits.[132] Efforts to improve the process and methodologies for forecasting load and DER adoption are ongoing through the DRP Working Group. This working group is charged with proposing methodologies and assumptions for DER adoption scenarios, and developing approaches to disaggregate forecasts to the circuit level. This group is also exploring ways to improve the coordination of the DRP with other planning processes in the state (i.e., the Integrated Resource Planning process, the IEPR demand forecast, and California Independent System Operator's Transmission Planning Process), in terms of process schedule and consistency of methodology and results, and how to address divergence of DER inputs from statewide planning assumptions.[133]

The results of the SDG&E's integration capacity analysis are displayed in an online heat map, which shows the capacity for each line segment for the following DER types:[134]

- EV – Residential (EV Rate)
- EV – Residential (TOU Rate)
- EV – Workplace
- PV

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[130] Ibid.

[131] Ibid.

[132] San Diego Gas & Electric, "Application of San Diego Gas & Electric Company (U 902 E) for Approval of Distribution Resources Plan," July 1, 2015, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5160.

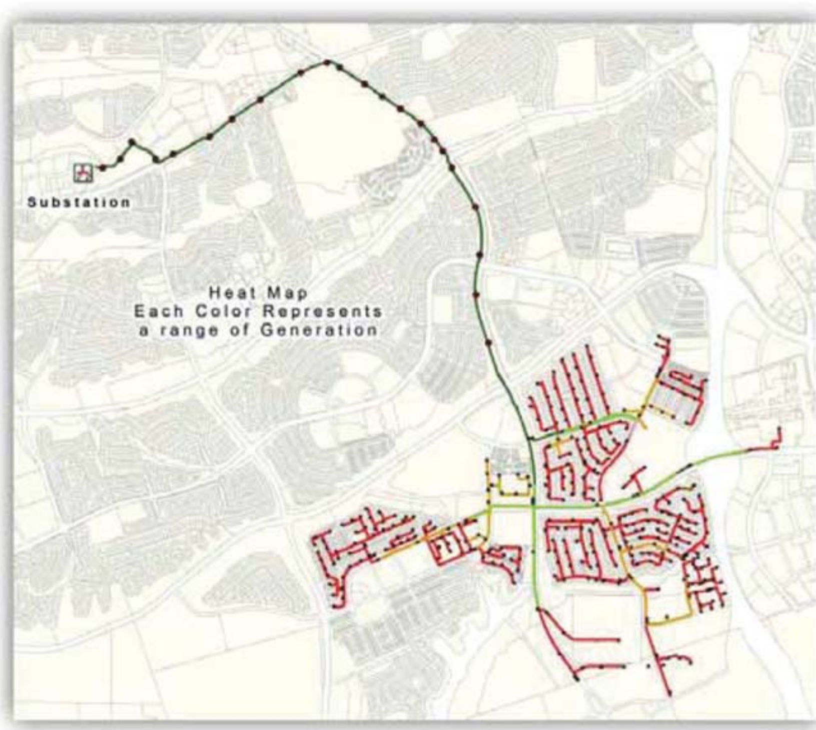
[133] CPUC, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769., No. 14-8–13 (February 27, 2017).

[134] San Diego Gas & Electric, "Demonstration Projects A & B Implementation Plans of San Diego Gas & Electric Company (U 902-E)," Rulemaking 14-08-013, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, June 16, 2016.

- PV with Storage
- PV with Tracker
- Storage – Peak Shaving
- Uniform Generation (Inverter)
- Uniform Generation (Machine)
- Uniform Load

SDG&E's maps now also include the locational net benefits of DERs that highlight where DERs can potentially benefit the distribution system by reducing the need system upgrades. The map outlines portions of feeders where reducing load would defer or eliminate investment needs, using color-coding to indicate the magnitude of the value of avoiding the project (in $/kW). Further, the map provides a timeframe layer that shows the timeframe in which DERs would need to be implemented to avoid or defer the utility investment and realize the avoided costs. The timeframes are categorized as either "short" (0-3 years), "medium" (3-6 years), or "long" (6-10 years). The timeframes incorporate forecasts of DERs and load growth.[135]

Figure 1. Example heat map



[135] San Diego Gas & Electric, "Enhanced Integration Capacity Analysis (ICA)," 2017, https://www.sdge.com/generation-interconnections/enhanced-integration-capacity-analysis-ica.

Notably, SDG&E's DRP does not address questions about how to solicit DERs that provide identified benefits, who should own DERs, and how they should be operated. Further, the DRP does not fully address rates and incentives to attract DERs where they are needed, utility cost recovery, and installations of DERs where there are no benefits or negative benefits.[136]

New York

New York's Reforming the Energy Vision (REV) initiative seeks to transform the existing electric grid to one that is efficient, flexible, resilient, and low-carbon, and that integrates increasing amounts of load management and distributed energy resources. Recognizing the need for greater transparency in how utilities operate the grid and plan for system needs, the Commission required the utilities to file Distributed System Implementation Plans (DSIPs). The DSIPs focus on how the utilities will facilitate, integrate, and manage their systems with increasing amounts of distributed energy resources, including energy efficiency, demand response, distributed generation, energy storage, and electric vehicles.[137]

The DSIPs are required to include the utilities' forecasts of demand, energy, and DER performance and penetration levels, and descriptions of the methodologies and processes used to develop these projections. Further, the DSIPs are required to include 8760 (all hours) load curves, voltage, power quality, and reliability data on a substation and individual feeder basis, and identify the granularity of the data to be provided to DER providers. The DSIPs must also provide information on plans to integrate of the interconnection process into the planning process.[138] More specific to distribution system planning, the DSIPs are required to include the following:

- *Delivery Infrastructure Capital Investment Plans*
    - Current reliability planning criteria and capital budgeting process for investment in delivery infrastructure, and how the planning and budgeting processes integrate consideration of DER resources
    - Historical spending and forward-looking budgets for transmission, substations, and distribution infrastructure, and for information technologies, communications, and shared services
    - Transmission and distribution projects that could be impacted by future or existing DER
- *Beneficial Locations for DER Deployment*

[136] San Diego Gas & Electric, "Application of San Diego Gas & Electric Company (U 902 E) for Approval of Distribution Resources Plan."

[137] Acadia Center, "Distributed System Implementation Plans in New York: Summary and Analysis," June 21, 2017, http://acadiacenter.org/document/distributed-system-implementation-plans-in-new-york-summary-and-analysis/.

[138] NY PSC, Staff Proposal: Distributed System Implementation Plan Guidance, No. 14- M-0101 (October 15, 2015).

- A plan for communicating, spatially and temporally, disaggregated zonal wholesale energy prices, to enable DER providers to make more informed decisions for investing in and siting new resources

- A process for collaborating with stakeholders to develop and implement ways for various DERs to avoid traditional grid-based solutions

- Specific areas in the utility footprint where: 1) there is an impending or foreseeable delivery infrastructure upgrade need, 2) DER may provide reliability or operational benefits but reliability deficiencies are not otherwise significant enough to be funded in a capital plan, and 3) there is no forecast delivery infrastructure need for years to come

- A list of specific infrastructure projects by location, the process used to identify the projects where DER solutions should be compared as potential alternatives, and what would be needed to avoid the infrastructure project

- The efforts to determine and share hosting capacity information, initially focused on locations with an impending or foreseeable delivery infrastructure upgrade, with market participants and stakeholders.[139]

Other DSIP elements include system operations, system data acquisition, data sharing, and customer engagement.[140] However, the DSIP process does not include the approval of projects, rate design, or cost recovery mechanisms.[141]

The New York utilities filed their DSIPs on June 30, 2016, and a supplemental joint DSIP on November 1, 2016. While the DSIPs provided some useful information for DER developers, they were criticized for failing to provide third-party vendors and customers with sufficient information to effectively implement DERs. The Public Service Commission noted that while the utilities' efforts to share system data "have shown promise" (such as through online data portals), improvements are still needed. Stakeholders frequently commented that the hosting capacity maps provided by the utilities were insufficient, with some commenters recommending that the maps be updated monthly and contain voltage, current generation, queued generation, peak and minimum load profiles, and limiting factor criteria violations.[142]

In its order, the Commission generally concurred with stakeholders, writing that "it is essential that the greatest amount of useful information is provided as early as possible to enable informed decision-making. The Utilities must improve the transparency of their distribution system needs, such that DER

[139] Ibid.

[140] Ibid.

[141] Acadia Center, "Distributed System Implementation Plans in New York: Summary and Analysis."

[142] NY PSC, "Order on Distributed System Implementation Plan Filings," In the Matter of Distributed System Implementation Plans, March 9, 2017, 12.

resources may be proposed as a means to address those needs."[143] The Commission further noted that "hosting capacity, interconnection portals, NWAs, energy storage, and aggregated customer data privacy" are "areas where near-term actions by the Utilities will have significant benefits," and where the Commission's order intends "to provide third parties with improved information and resources that will facilitate better decision-making and promote expansion of DERs by enabling the development of fully-informed business cases for DER investments."[144]

To facilitate greater information availability, the Commission ordered the utilities to further update their hosting capacity analyses, propose new standards for providing building energy management and benchmarking data, provide additional information for incorporating DERs into utility planning procedures, and deploy energy storage projects.[145] Moreover, the Commission will continue the proceedings to ensure that its Reforming the Energy Vision initiative achieves its goals.

DERs Providing Grid Services

As DER integration improves, customers will have the potential to provide a greater number of services to the distribution utility, such as peak load reductions and volt/VAR support through smart inverters or EV batteries. These services may allow the utility to defer investments that would have otherwise been made in order to address reliability or system stability issues. In recognition of these capabilities, innovative jurisdictions are placing greater emphasis on non-wires alternatives (NWAs) at the distribution level.

Connecticut

One of the methods by which Connecticut is pursuing non-wires alternatives is through its utilities' grid-side system enhancements projects. However, not all the projects have been approved due to cost-effectiveness issues.

<u>Grid Side Enhancement Demonstrations</u>

Section 103 of Public Act 15-5 requires electric distribution companies to file one or more proposals to the Department of Energy and Environmental Protection (DEEP) for demonstration projects to build, own, or operate grid-side system enhancements. Proposals must show that they will:

1) Demonstrate and investigate reliable and efficient integration of distributed energy resources into the electric distribution system;

2) Maximize the value of DERs to the electric grid, electric ratepayers, and the public; and

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[143] Ibid., 9.

[144] Ibid., 10.

[145] NY PSC, "Order on Distributed System Implementation Plan Filings."

3) Enhance the programs, products, and incentives available through the Connecticut Green Bank, the Connecticut Energy Efficiency Fund, and other similar programs

In addition, distribution companies are required to submit at least one proposal including an energy storage system or systems.[146] Accordingly, the utilities have proposed NWA projects through their Grid Side Enhancement Demonstrations.[147]

United Illuminating is considering an NWA in the form of an automated demand response management system for large facilities to relieve a feeder at the Woodmont Substation. For energy generated during summer peak hours, participants will receive compensation through the Demonstration Project DER Rate rider at a rate of $0.05/kWh, on top of any pre-existing net metering arrangement.[148]

Also targeting the Woodmont Substation, United Illuminating proposed 1) analysis of circuit-level daily load shape, net of DER, 2) DER hosting capacity analysis, resulting in the development of capacity maps that will be incorporated into the company's distribution system planning process, and 3) a 1.25 MW, 5 MWh storage system at a cost of $5.6 million plus operations and maintenance costs of $300,000 per year.[149] While a 2017 determination by the Connecticut Department of Energy and Environmental Protection approved the DER forecasting and DER hosting capacity analysis proposals, it did not approve the energy storage proposal on the basis of that the benefits (avoiding $1.5 million in distribution system upgrades at the Woodmont substation) were insufficient to justify the cost. DEEP noted that, "while DEEP does not believe that the pilot program or test projects need to demonstrate that they will be cost effective to warrant approval, they should offer a reasonable potential for doing so."[150]

Like United Illuminating, Eversource submitted a proposal for 1) DER hosting capacity analysis and 2) energy storage, as well as 3) a DER customer portal and management system. The DER hosting capacity map, designed to indicate the maximum amount of DER that can be accommodated by each portion of the circuit, was approved by DEEP. Eversource's energy storage proposal targeted the Blair 15M substation at a capital expenditure cost of $10 to $13 million, plus annual upkeep costs of $350,000. As Eversource provided no estimate of benefits from this proposal, it was denied based on the evidence provided. The DER customer portal and management system, to facilitate DER interconnection, was approved.[151]

Eversource had considered a Grid-side Enhancement Demonstration project for the Uncasville substation, but chose a different project because the value of the deferral was significantly reduced

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[146] DEEP, Demonstration Projects for Grid-Side System Enhancements Notice of Final Determination (February 1, 2017).

[147] NEEP, "EM&V Forum and Policy Brief: State Leadership Driving Non-Wires Alternative Projects and Policies," January 2017, 2, http://www.neep.org/sites/default/files/resources/NWA%20brief%20final%20draft%20-%20CT%20FORMAT.pdf.

[148] Ibid.

[149] DEEP, Demonstration Projects for Grid-Side System Enhancements Notice of Final Determination at 8.

[150] Ibid., 7.

[151] DEEP, Demonstration Projects for Grid-Side System Enhancements Notice of Final Determination.

when a large customer ceased operations there. In the project selection process, NWA was one of the evaluation criteria and was assigned 20% weight.[152]

Maine

Boothbay Harbor

In June 2010, the Maine Public Utility Commission issued an order approving, in part, Central Maine Power's Maine Power Reliability Program petition to address reliability needs in the Mid-Coast area. The order called for Central Maine Power and GridSolar, acting as the Smart Grid Energy Services Operator, to file a plan to further evaluate a smart grid platform, non-transmission alternative (NTA) pilot projects, and reliability needs. In March 2011, Central Maine Power and GridSolar set forth a plan for an NTA pilot project in the Mid-Coast area.[153] The Commission approved a pilot project to reduce peak load in the Boothbay region by 2 megawatts, to avoid the otherwise-required $18 million rebuild of the 34.5 kV line from Newcastle to Boothbay Harbor.[154]

In response to two successful Requests for Proposals, bids were accepted for a variety of NTA resources. From late 2013 to early 2015, 1.8 MW of NTAs were deployed,[155] including a 500 kW battery, a 500 kW diesel back-up generator, 308 kW of solar photovoltaics, 243 kW of efficient lighting and air conditioning, 224 kW of peak load shifting, and 29 kW of demand response.[156]

GridSolar's final report on the pilot project included a positive assessment of the pilot's performance, indicating that testing repeatedly demonstrated that dispatched NTAs reduced upstream substation loads at levels sufficient to meet grid reliability criteria and to avoid the need for transmission investments.[157] External review found that energy conservation and efficiency NTA resources generally performed as expected, but suggested that modification of NTA contract language and measurement and verification methodologies was appropriate[158].

Smart Grid Coordinator

One of the most innovative aspects of Maine's NWA process is the use of a non-utility entity in identifying and implementing NWAs.

In its order regarding the Maine Power Reliability Program, the Maine Public Utilities Commission also initiated a separate docket to consider the policy objectives of the 2010 Smart Grid Policy Act and the

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152 NEEP, "EM&V Forum and Policy Brief: State Leadership Driving Non-Wires Alternative Projects and Policies," 2.

153 MPUC, Investigation into the Designation of Non-Transmission Alternative (NTA) Coordinator, No. Docket No. 2016-00049 (April 4, 2016).

154 GridSolar, LLC, "Boothbay Sub-region Smart Grid Reliability Pilot Project: Final Draft for Review," March 17, 2017.

155 Ibid., 49.

156 Ibid., 1.

157 Ibid., 2.

158 Ibid.

role of one or more smart grid coordinators in furthering those objectives. The role of this coordinator involves developing cost-effective alternatives to traditional utility investments to improve the overall electric system reliability and efficiency, reduce ratepayers' costs while simultaneously improving the overall efficiency of electric energy resources, reduce and better manage energy consumption, and reduce greenhouse gas emissions. This coordinator, in developing cost-effective NTAs, would be promoting one or more of the following smart grid components identified in the Smart Grid Policy Act:

- Increased use of digital information and control technology to improve the reliability, security and efficiency of the electric system
- Deployment and integration of distributed resources and generation, including renewable resources.
- Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.
- Deployment and integration of advanced electricity storage and peak shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.[159]

Unlike in other states, the Maine Public Utilities Commission pushed for a neutral third party, rather than the utilities, to manage the NWA planning process.[160] Resolution of the Smart Grid Coordinator docket (2016-00049) is pending.

New York

As part of the Reforming the Energy Vision initiative, New York is aggressively pursuing non-wires alternatives, with over 25 projects in progress.[161] However, it is not the number of projects that represents the most innovative practice, but rather the process by which NWAs are being identified and developed. Where once NWAs were the domain of select pilot projects, they are now being considered in a more rigorous and standardized manner as part of the utilities' regular capital planning processes.

New York's approach to NWAs begins with the development of system needs as part of each utility's annual capital plan, which relies on a multi-year (typically five-year) capital forecast. In this plan, the utilities identify and quantify the specific system needs driving capital projects, including timing and location, and perform an initial screen of whether NWAs might be capable of providing an alternative to a traditional solution. If an NWA could be an option, the utility develops data for inclusion in RFPs, issues

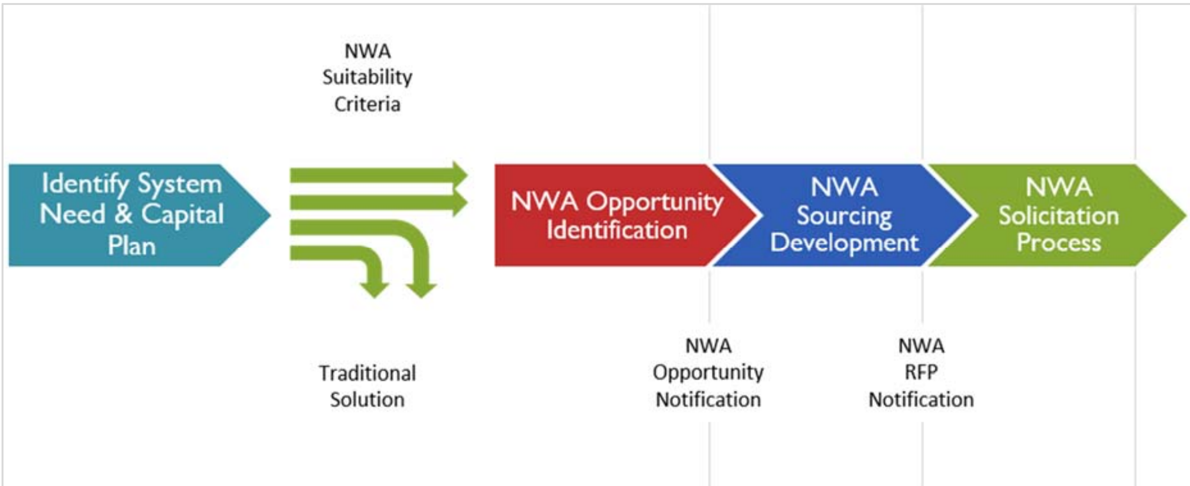
[159] MPUC, Investigation into the Designation of Non-Transmission Alternative (NTA) Coordinator at 2.

[160] NEEP, "EM&V Forum and Policy Brief: State Leadership Driving Non-Wires Alternative Projects and Policies," 1.

[161] NEEP, "EM&V Forum and Policy Brief: State Leadership Driving Non-Wires Alternative Projects and Policies."

a solicitation, evaluates solicitation responses, negotiates a solution, and ultimately awards a contract if a viable solution is found.[162] This process is summarized in the graphic below.

Figure 2. Non-wires alternatives process



Source: Adapted from Joint Utilities, "Supplemental Information on the Non-Wires Alternatives Identification and Sourcing Process and Notification Practices," Case 16-M-0411, May 8, 2017.

To increase the transparency of utility investment decisions, the New York Public Service Commission required the utilities to develop standardized suitability criteria for evaluating NWA opportunities.[163] The three primary criteria are:

1) Project type: The project categories most conducive to non-wires alternatives are load relief and some reliability projects, while power quality, conservation voltage reduction, resiliency, damage failure, asset condition, new business, and service upgrade might only be appropriate under more limited conditions.

2) Timeline: For an NWA to displace a traditional project, sufficient lead time prior to the project need date is required to complete the procurement process—including time to develop and issue an RFP, review bids, execute contracts, and implement the resource. While the time required will vary depending on factors such as project size, complexity, and customer demographics, the utilities note that it may be as long as five years.

3) Cost: The utilities propose company-specific cost floors for various project types to serve as a guideline for NWA suitability. This criterion is intended to indicate whether NWAs

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[162] Joint Utilities, "Supplemental Information on the Non-Wires Alternatives Identification and Sourcing Process and Notification Practices," Case 16-M-0411 – In the Matter of the Value of Distributed System Implementation Plans, May 8, 2017.

[163] NY PSC, "Order on Distributed System Implementation Plan Filings."

are likely to be cost-competitive, taking into account the transaction and opportunity costs associated with smaller scale projects. [164]

In addition, each utility has developed utility-specific NWA suitability criteria, accounting for the unique characteristics of each utility.

The procurement process plays a critical role in the success of NWAs. Third-party DER providers must have adequate and timely information regarding NWA opportunities, and the process must be streamlined to minimize the costs incurred by parties responding to RFPs and reduce the time necessary to identify and implement a solution. To streamline the solicitation process, the New York utilities are undertaking the following actions:

- Standardizing data and requested performance characteristics;
- Maintaining a list of each utilities' NWA opportunities on their respective websites and a common list of all NWA opportunities on a single website; and
- Pre-qualifying vendors to reduce the procurement timeline.[165]

Prior to developing the new NWA procurement process, New York had been experimenting with NWAs through several pilot projects. The most high-profile of these projects, Consolidated Edison Company's (Con Edison) proposed its Brooklyn/Queens Demand Management (BQDM) program, was approved in December 2014. The BQDM program was designed to address forecasted summer overloads in the Brooklyn and Queens areas of New York. Instead of constructing a new area substation, a new switching station, and new sub transmission feeders (at a cost of roughly $1 billion), Con Edison proposed implementing targeted distributed energy resources and other traditional utility-side solutions, at a much lower cost.[166]

BQDM includes 41 MW of non-traditional resources, including demand response, energy efficiency, fuel cells, combined heat and power, solar, battery storage and thermal storage, paired with 17 MW of traditional utility infrastructure investment (capacitor bank installations providing 6 MW of capability and 11 MW of load transfers).[167]

Demand response resources were procured through a descending clock auction format in July 2016. The auction was successful and exceeded expectations in terms of diversity of suppliers and technological solutions, and new entrants.[168] However, in early 2017, six of ten awarded bidders claimed full or partial deficiency on their 2017 award, representing 7.58 MW (out of 11.52 MW total 2017 load reduction

[164] Joint Utilities, Supplemental Distributed System Implementation Plan, No. 16- M-0411 (November 1, 2016).

[165] NY PSC, "Order on Distributed System Implementation Plan Filings."

[166] NY PSC, "Order Establishing Brooklyn/Queens Demand Management Program," Case 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program (New York Public Service Commission, December 12, 2014).

[167] Ibid., 3.

[168] Consolidated Edison, "BQDM Quarterly Expenditures & Program Report," 2017, 26–27.

procured). In explaining the reasons for the deficiencies, DR providers noted that the time between bid award and customer enrollment deadlines was insufficient. DR providers that planned to implement storage reported difficulty with the length and complexity of the permitting process.[169]

In January 2017, Con Edison requested an extension of time to spend the approved BQDM program budget. In the petition, Con Edison noted that the program is on track to meet its goals by June 2018, helped by lower economic growth forecasts, slower than anticipated new construction, and load factor improvements due to capacitor bank installations.[170] While NY-BEST expressed support for the proposed extension, two parties, the City of New York (the City) and Peak Power, raised concerns:

Performance risk: The City questioned how Con Edison will improve management of performance risks associated with the extension. In opposition to the extension, Peak Power noted that some BQDM participants have come up short on their pledges. To balance procurement risks, the Commission advised Con Edison to implement both traditional utility direct procurements as well as market-based/auction procurements.[171]

Forecasting accuracy: Both Peak Power and the City expressed concern about forecasting. Specifically, Peak Power questioned Con Edison's ability to forecast the BQDM program given the size of the BQDM relative to forecasting errors. In response to these concerns, Con Edison provided information about its forecasting methodologies and why the forecasted demand declined, in part highlighting the success of the program: 1) completion of load transfers, 2) achieved BQDM load reductions, and 3) lower economic activity in the area than originally forecast.[172]

Cost effectiveness: The City raised concerns about cost effectiveness—customers would be paying for both short-lived assets and traditional infrastructure shortly thereafter. In response to this concern, the Commission indicated that "Con Edison should balance anticipated useful life of customer-side DER with expediency of achieved load reductions necessary to ensure maximum benefit of the BQDM program."[173]

Clarity on what is being deferred: The City further noted that it was unclear whether the BQDM extension would enable deferral of the Glendale project, a traditional solution involving new transformers and load transfer that would enable longer deferral of the Gowanus Expansion (one of the traditional grid-side solutions that BQDM was supposed to defer). Con Edison responded that the 10-19 MW of non-traditional resources needed to defer the Glendale Project could be attained within the previously authorized budget for BQDM.[174]

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[169] Ibid., 27.

[170] NY PSC, Order Extending Brooklyn/Queens Demand Management Program, No. 14- E-0302 (July 13, 2017).

[171] Ibid., 11.

[172] Ibid., 8.

[173] Ibid., 11.

[174] Ibid., 7.

Double incentives: The City noted concerns about potentially providing Con Edison with double incentives for the same activity (e.g. for the Glendale project). The Commission clarified that the Glendale project will not be a separate NWA, thus mitigating the risk of double incentives in this case.

In July 2017, the Commission granted the extension of time with no termination date. The program is still subject to the previous budget caps and shareholder incentive mechanisms. In its order, the Commission noted that "Con Edison has been consistently successful in meeting its implementation checkpoints on time and under budget."[175]

Since Con Edison implemented BQDM, the rest of the investor-owned utilities have followed suit and implemented NWA projects to defer their proposed distribution projects. For NWA opportunities, the utilities identified specific distribution areas of concern that need new investment due to expected load growth and issued request for proposals for customer-sited distributed energy resources, such as energy efficiency, demand response, storage, and solar photovoltaics (PV).[176] The utilities have also sought to implement non-traditional utility-side solutions, such as batteries connected to substations and voltage optimization.

3.2. Integrating Electric Vehicles

Electric vehicles (EVs) have incredible potential to assist in the reduction of greenhouse gas emissions and save utilities and ratepayers money. For these reasons, jurisdictions are becoming increasingly interested in promoting EVs and managing EVs to provide grid services, such as demand response. EV promotion, in conjunction with supplying the energy from renewable resources, can help to address environmental concerns of communities like Boulder, Colorado. Additionally, to the extent that EV operating costs are less than gasoline-fueled vehicles, EV infrastructure can help lower customers' transportation bills by allowing them to reduce or eliminate gasoline purchases in exchange for slightly higher electric bills. This section provides a brief summary of utility investments in EV infrastructure and the use of EVs for direct load management. Smart rate designs for EVs are discussed in the following section.

Utilities are increasingly looking to directly engage in the development of EV infrastructure. California leads the country in such investments, with all three major investor-owned utilities in the state engaged in commission-approved EV infrastructure initiatives. For example, San Diego Gas & Electric (SDG&E) recently launched a pilot program called "Power Your Drive," which plans to install 3,500 private charging stations at apartments, condominiums, and businesses. Charging stations in disadvantaged

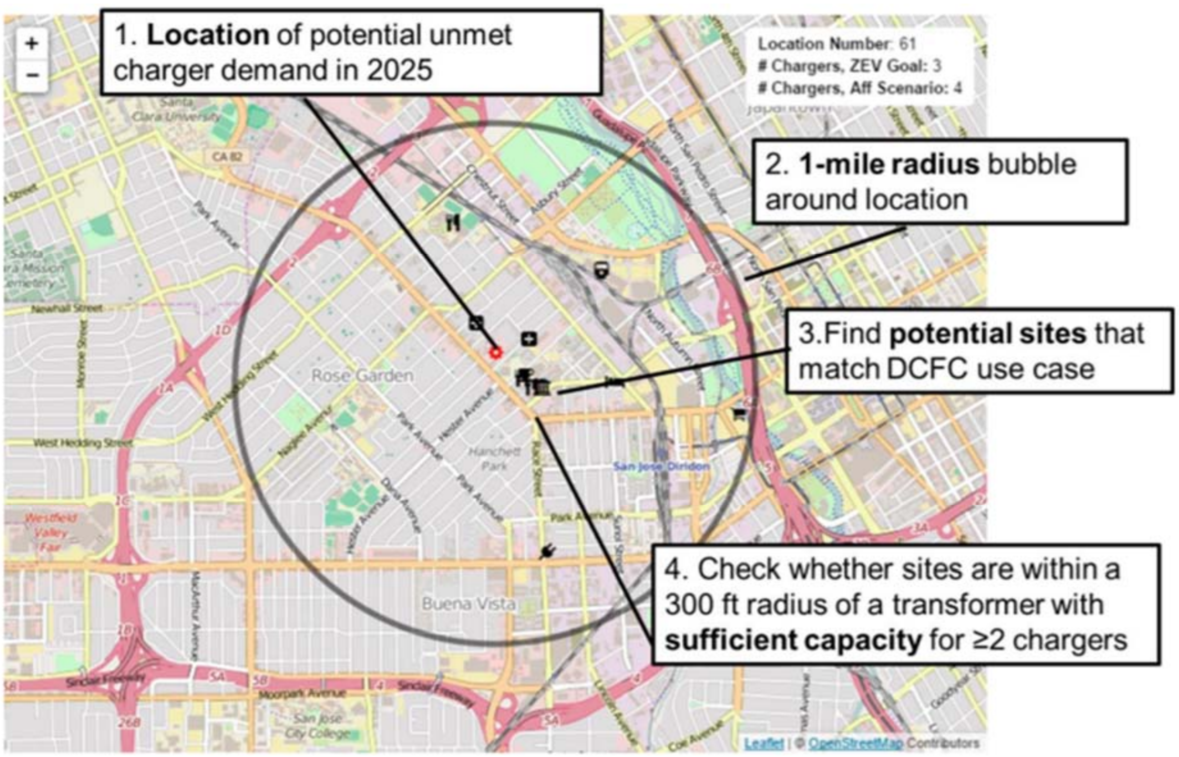
[175] Ibid., 3.

[176] Examples of NWA RFPs are available as follows: Con Edison at https://www.coned.com/en/business-partners/business-opportunities/non-wires-alternatives; NYSEG at http://www.nyseg.com/SuppliersAndPartners/NonWiresAlternatives/ProjectOpportunities.html; Niagara Mohawk/National Grid at http://energystorage.org/resources/rfp-non-wires-alternative-solutions-old-forge-new-york-area.

communities will be installed at no cost, and other charging stations will have a one-time participation payment of $630 per charger for businesses and $235 per charger for apartments and condominiums.[177] Electricity will be charged at a dynamic vehicle-grid integration rate that encourages charging during non-peak hours, and participants will have the option of having the EV drivers who use the station pay for their electricity or the property owner pay for the charger's electricity.

To facilitate the development of EV chargers in beneficial locations, Pacific Gas & Electric (PG&E) has deployed a Direct Current Fast Charger (DCFC) Micro-Siting Tool, a mapping tool which assists in the identification of potential sites for DCFCs within the PG&E service area. A DCFC is a fast charger than can recharge the entirety of a standard EV battery within approximately 30 minutes, and typically has a demand of 50 kW. DCFCs are critical for reducing range anxiety and therefore encourage the adoption of EVs. The project includes an interactive map tool with over 14,000 sites within 300 1-mile radius bubbles that have been identified as areas expected to meet demand shortages by 2025. Users can zoom into the unmet demand bubbles to review more granular data on potential DCFC sites, including site address and site type (see Figure 3 for an example of the tool's interface). The tool can provide useful information for charging network developers and planners, utilities, automakers, and municipalities.

Figure 3. PG&E's DCFC Micro-Siting Tool[178]



[177] San Diego Gas & Electric, "Power Your Drive FAQ," SDG&E, 2016, https://www.sdge.com/clean-energy/electric-vehicles/power-your-drive-faq.

[178] Pacific Gas & Electric Company, "Electric Program Investment Charge (EPIC) Final Report: Project 1.25 DC Fast Charging Mapping," September 31, 2016, 17.

Southern California Edison (SCE) has proposed a number of pilots as a part of its Transportation Electrification initiative. Notable among these are:

- Electric Transit Bus Make-Ready Program. This program seeks to expand the number of on-route charging stations for electric commuter buses operating in the SCE service area. The one-year pilot will work with transit agencies to install the charging infrastructure, and will also provide a rebate to transit agencies that purchase charging stations for their electric commuter buses.[179]

- EV Driver Rideshare Reward Pilot. This program will award rideshare and taxi drivers that use an EV and meet a daily ride threshold with a cash reward. The one-year pilot seeks to promote the purchase of EVs within the rideshare and taxi industries, as well as introduce rideshare and taxi customers to the experience of being a passenger in an EV.[180]

- Urban DC Fast Charging Clusters Pilot. This program will install five DCFC sites in high-density areas in SCE's service area. The pilot seeks to provide more charging options in urban areas and to provide information on charging behaviors of end-users.[181]

Managed Charging / Direct Load Management

Managed charging, defined as "a combination of infrastructure and communication signals sent directly to a vehicle or via a charger to control a charging event," can sidestep the reliance on customer response that indirect managed charging efforts (e.g. TOU rates and demand charges) rely on in order to maximize benefits to the grid and to customers.[182] Potential benefits include:

- The ability to provide demand response

- Reduced ramping rates for generation resources (as illustrated in the famous "duck curve")

- Demand charge reductions

Several utilities have explored managed charging via pilots, including Pepco Maryland. In its Maryland service area, Pepco enrolled more than 100 EV customers in various time-varying rates and installed ClipperCreek chargers with an embedded Itron revenue-grade meter for 35 residential EV owners.[183] The chargers allowed the EVs to respond to demand response (DR) events – when a DR event was called by

[179] Southern California Edison, "SCE January 2017 Transportation Electrification Filing," April 27, 2017, 17.

[180] Ibid., 15.

[181] Ibid., 16.

[182] Smart Electric Power Alliance, "Utilities and Vehicles: The Case for Managed Charging," April 2017.

[183] Pepco, "Pepco Demand Management Pilot for Plug-In Vehicle Charging in Maryland: Final Report – Results, Insights, and Customer Metrics (Revised)," Case No. 9261, (April 2016), http://webapp.psc.state.md.us/newIntranet/casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\Casenum\9200-9299\9261\\122.pdf.

Pepco, vehicles that were charging would reduce their charging rate from Level 2 to Level 1 for an hour. Customers had the option to opt-out of the DR events. Ultimately, the pilot was discontinued due to the costs involved in the utility communicating to the EVs. However, communication costs are likely to continue to fall as the technology progresses, and the benefits of managed charging during DR events may soon outweigh the costs associated with developing communication networks. A Pepco report notes that "meter comparisons showed that Itron meters could be a useful tool for demand response events as well as vehicle metering once the communication issues are resolved."[184]

Pacific Gas & Electric (PG&E) has completed the first phase of its ChargeForward program, in which demand response events were used to delay EV charging. PG&E sent demand reduction requests of up to 100 kW to BMW, who then identified EVs to delay charging by up to one hour per day. EV owners were selected based on their needs, and had the option to opt-out of the program. BMW provided backup energy from an energy storage system powered by "second life" EV batteries in case there were EV owners who opted out of the delayed charging events. The results showed that 94 percent of the 192 demand response events between July 2015 and October 2016 were able to successfully reduce the load of EVs by 100 kW.[185]

3.3. Innovative Rate Designs and Tariffs

Rate design can play an important role in the evolution of the grid. Electricity rates not only recover costs, but also provide customers with price signals that influence how customers use electricity and whether to make investments in distributed energy resources, electric vehicles, or other technologies. For this reason, care must be taken to design electricity rates to provide customers with efficient price signals regarding the cost of electricity consumption, as well as the value of providing services to the grid. Equally important, rate designs must also be simple enough for customers to understand and respond to, and should maintain customer equity.

If done well, rate design can encourage customers to reduce energy consumption through investments in energy efficiency or distributed generation, and reduce load during the hours when it matters most in response to time-varying rates. Good rate design can reduce total utility costs, ultimately allowing for the reduction of customers' electric bills. Lower or more stable electric bills were cited as driver of municipalization by all communities interviewed in this report. Further, good rate design can also support beneficial electrification (such as electric vehicles) by providing discounted rates during hours when electricity is inexpensive, or when there is excess renewable generation on the grid. As noted earlier, beneficial electrification can help to address communities' environmental policy goals, such as in the case of Boulder, Colorado.

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[184] Ibid., 10–11.

[185] Pacific Gas & Electric Company, "PG&E and BMW Partner on Next Phase of Pilot Studying Advanced Electric Vehicle Charging," November 14, 2016, https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20161114_pge_and_bmw_partner_on_next_phase_of_pilot_studying_advanced_electric_vehicle_charging_.

If rate design is approached ineffectively, however, it can become a substantial obstacle, reduce customers' control over their bills, and distort efficient price signals. As the grid modernizes, utilities must consider how rate design, in combination with DERs, can help the system evolve in an efficient manner to ultimately benefit all customers.

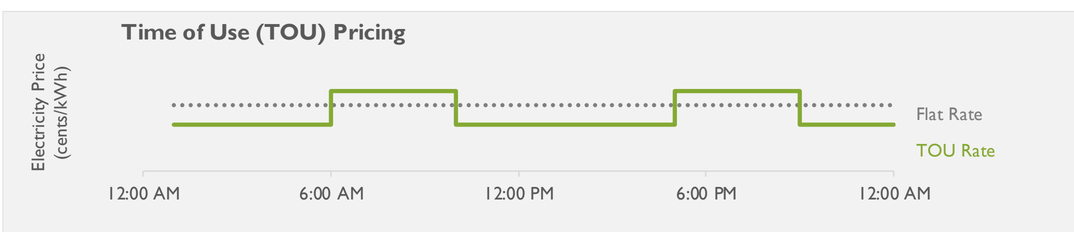
Time-Varying Rates

Standard residential electricity rates include a fixed charge and a volumetric charge ($/kWh). The charge is typically a flat rate or other time-invariant rate, which charges customers the same price per kilowatt-hour, regardless of when that energy is consumed. Such time-invariant energy rates fail to reflect that electricity production and distribution costs can vary wildly over the course of a year, and even over the course of a single day. In contrast, time-varying rates can provide strong price signals to customers to reduce consumption when it is most valuable to the system. Reducing peak demand during high-priced hours can have large customer benefits, such as reductions in wholesale market prices and lower power plant emissions. Such benefits have been previously recognized by the DC Public Service Commission.[186]

Because they reduce peak demand, time-varying rates are considered a form of demand response. Although they are not dispatchable, time-varying rates can have considerable impact by encouraging many customers to make small adjustments to the timing of their energy consumption, resulting in a flatter load curve for the entire system.[187]

The most common forms of time-varying rates are described below, along with a stylized depiction of how each rate could be implemented.

- *Time-of-Use (TOU) Rates:* TOU rates consist of two or more pricing tiers, based on pre-set time periods. Electricity is priced higher during hours when the peak is more likely to occur, and lower during hours that are generally off-peak. An advantage of this type of rate structure is that it has low financial risks to customers, because the pricing is known ahead of time and customers choose whether to curtail their electricity use.



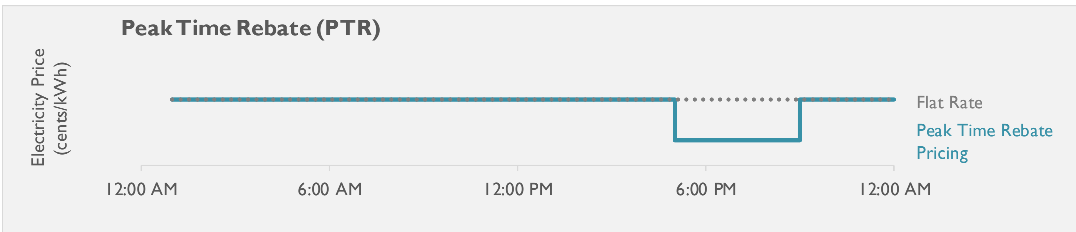
- *Critical Peak Pricing (CPP):* This rate structure is often used in conjunction with TOU rates, but can be used with an otherwise flat rate structure as well. Critical peak pricing implements a very high price tier that is only triggered for very specific events, such as

[186] DC PSC, "Order No. 17375," FC 1086, In the Matter of the Investigation into the Potomac Electric Power Company's Residential Air Conditioner Direct Load Control Program, n.d., 33.

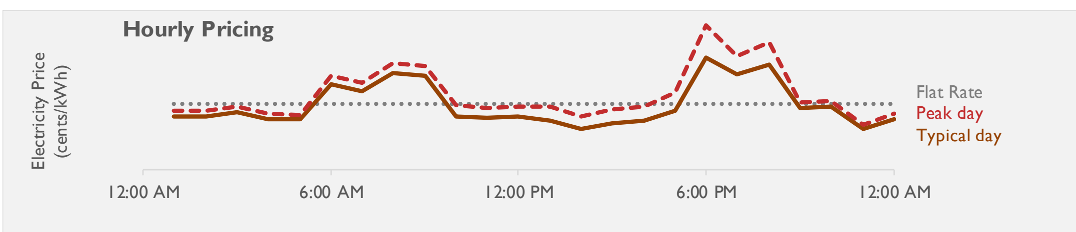
[187] CPUC, "Decision Adopting Policy Guidelines to Assess Time Periods for Future Time-Of-Use Rates and Energy Resource Contract Payments," Decision 17-01-006, January 23, 2017.

system reliability or peak electricity market prices. The timing of the events is generally not known until a day in advance, and the events typically last for only 2–6 hours.

- *Peak Time Rebates (PTR)*: A peak time rebate program is similar to critical peak pricing, except that customers earn a financial reward for reducing energy relative to a baseline, instead of being subject to a higher rate. As with critical peak pricing, the number of event days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.[188]



- *Real-Time Pricing and Hourly Pricing:* These rates charge customers for electricity based on the wholesale market price rather than a preset rate schedule.[189] Rates fluctuate hourly or in 15-minute increments, reflecting changes in the wholesale price of electricity. Customers are typically notified of prices on a day-ahead or hour-ahead basis.



Time-varying rates have been shown to be highly effective in reducing peak period demand, but the effectiveness depends on how the rate is designed. The graph below shows the results of 163 treatments in 34 projects on four continents from The Brattle Group's database of pricing studies.[190] As

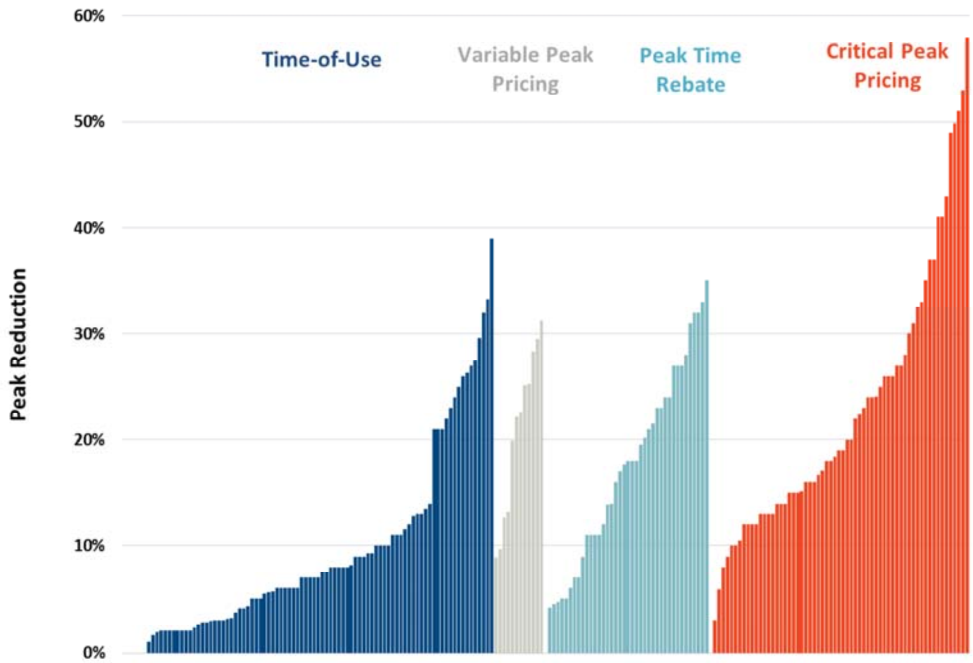
[188] Federal Energy Regulatory Commission, "Assessment of Demand Response and Advanced Metering" (Washington, DC, 2010).

[189] Ibid.

[190] Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing" (Brattle Group, July 2013), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2288116.

shown in the graph, critical peak pricing typically delivers the greatest load reductions, while TOU rates and peak time rebates exhibit more modest impacts.

Figure 4. Residential peak reductions by time-varying rate type



Source: Faruqui Ahmad. "Arcturus." The Brattle Group.

Time-Varying Rates as Demand Response in Maryland

Pepco Maryland offers peak time rebates to its residential customers when events are called during the summer months of June through September, whereby customers who reduce their load relative to their baseline receive a credit of $1.25/kWh. Customers are not required to sign up for the program; rather residential customers are defaulted onto this rate. As with any PTR program, customers can only be rewarded for reducing consumption during peak hours and are not penalized if they do nothing to change their behavior.

In October 2013, Pepco DC proposed a peak time rebate program for the District similar to its program at its sister utility in Maryland.[191] Although Pepco's analysis projected that a similar program in the District of Columbia would have a benefit-cost ratio of 3.3, the DC Public Service Commission ultimately denied Pepco's application due to concerns regarding that market revenues would not cover the costs of the program, and that changes to the PJM capacity market rules would require resources to perform year-round, thereby limiting opportunities and revenues for the summer peak time rebate program.[192]

[191] Pepco, FC 1083, FC 1086, Potomac Electric Power Company's District of Columbia Dynamic Pricing Proposal, October 7, 2013.

[192] Public Service Commission of the District of Columbia, "Order No. 17375," FC 1086, FC 1109, February 6, 2014, 34–35.

Given this background, it is instructive to review the experience of Pepco's Maryland PTR program in recent years, as it offers a glimpse of what the District would have experienced had it implemented a similar PTR program.

Pepco's Maryland PTR program costs are primarily recovered through PJM wholesale market revenues (both energy and capacity). Despite being a "non-dispatchable" demand response program, customer response can be projected with almost the level of certainty achievable from direct load control, allowing Pepco to bid the load reductions into the wholesale markets.

If PJM market earnings are insufficient to cover the costs of the program, the remaining costs are recovered through a surcharge on customer bills. In 2015, PJM market revenues were approximately equal to the costs of the Maryland peak time rebate program.[193] In 2016, market revenues were greater than the costs of the program, leading to a bill credit of approximately $0.33 per month for Pepco's Maryland customers.[194] Pepco called three events in 2016 and estimates that, on average, 73% of residential customers participated in each event, for an average rebate credit of $5.33.[195] The program has successfully demonstrated that peak time rebates can be effective in reducing summer peaks.

In recent years, however, PJM has implemented reforms to its capacity market, leading to a precipitous decline in revenues for seasonal demand response. PJM has been transitioning to a market in which resources are required to be "capacity performance" (CP) resources, with the ability to perform year-round or face stiff penalties for non-performance. Seasonal demand response can participate in the RPM through the aggregation of winter and summer resources, although the seasonal resource will only receive compensation during the months that it is qualified to provide capacity. Resources that tend to operate on a seasonal basis are permitted to aggregate across locational deliverability areas. PJM clears annual and seasonal offers independently to ensure that sufficient capacity of summer and winter resources are procured.[196]

The changes to PJM's capacity market have led to a dramatic reduction in demand response clearing in the capacity market, as well as revenues for demand response. In the 2019/2020 auction, 80 percent of resources were required to be CP resources. In Pepco's zone, demand response that did not qualify as a capacity performance resource cleared at only $0.01/MW-day, while CP resources cleared at $100/MW-day. The vast majority of demand response (94 percent) did not clear as a CP resource.[197] The 2020/2021 auction required 100 percent of resources to be capacity performance resources, and cleared nearly 50 percent less demand response than the 2015/2016 auction. Pepco Holdings (Pepco's

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[193] Public Service Commission of Maryland, "The EmPOWER Maryland Energy Efficiency Act Standard Report of 2016 with Data for Compliance Year 2015," April 2016, 20.

[194] Public Service Commission of Maryland, "2016 Annual Report for the Calendar Year Ending December 31, 2016," April 4, 2017, 20, www.psc.state.md.us/wp-content/uploads/2016-MD-PSC-Annual-Report.pdf.

[195] Potomac Electric Power Company, "EmPOWER Maryland Report," Case 9155, January 31, 2017, 62.

[196] PJM, "Seasonal Resources and Aggregation in RPM," April 7, 2017, http://www.pjm.com/~/media/committees-groups/subcommittees/drs/20170407/20170407-item-04a-intermittent-resources-in-rpm-training.ashx.

[197] PJM, "2019/2020 RPM Base Residual Auction Results," May 24, 2016.

parent company) reports that "Because the quantity of available winter resources was lower than the quantity of available summer resources, approximately 30% of the Companies' available summer resources clear[ed] in the Auction."[198]

To summarize, the following trends characterize recent demand response performance in the auction:

- Most of the demand response resources bid in by Pepco Holdings did not clear the auction in 2020/2021
- Because seasonal resources now must pair with another resource to clear the auction, summer peak time rebate programs receive compensation for only a portion of the year, according to their seasonal nature.
- Capacity market prices in general have declined. The most recent auction produced a clearing price of only $86.04/MW-day for Pepco's territory, relative to prices of approximately $150/MW-day in 2015/2016.

Although these trends do not bode well for the cost-effectiveness of peak-time rebates, they do not necessarily mean that price-responsive programs are not cost effective. Wholesale revenues provide a direct stream of benefits for such programs, but are only one of many benefits attributable to reductions in demand due to time varying rates. Other benefits may include wholesale market price mitigation, avoided emissions, and avoided distribution capacity. In fact, Pepco's projected benefits associated with PTR are so large that even if the benefits were reduced by two-thirds, the program would still be cost-effective.[199]

Pepco's estimated benefits and costs are shown in Table 4, below. Due to capacity market changes, these benefits are now much less than initially projected, but still exist. Further, other benefits have not been quantified.

[198] Pepco Holdings, "Letter to the Maryland Public Service Commission in Case Nos. 9207, 9155 and 9156," June 12, 2017, 3.

[199] Note that bill credits are not considered a cost in Pepco's calculation. In some jurisdictions, bill credits are included as part of the program costs.

Table 4. Pepco's benefit-cost analysis results

Benefits	Net Present Value
Capacity Market Earnings	$17,752,375
Energy Market Earnings	$380,925
Capacity Price Mitigation	$38,835,170
Total Benefits	**$56,968,470**
Costs	
Customer Education	$10,711,821
IT Support	$1,140,118
External Analytical Support	$489,166
Outbound Messaging	$4,331,563
Utility Administration	$611,457
Total Costs	**$17,284,125**
Benefit-Cost Ratio	**3.30**

Source: Public Service Commission of the District of Columbia, "Order No. 17375," FC 1086, FC 1109, February 6, 2014, p. 12.

From these estimated costs and benefits, it is clear that time-varying rates could still have significant benefits for DC customers, even under PJM's new capacity performance market rules. However, other rate designs could potentially result in even greater net benefits for DC customers. Although peak time rebates are popular with customers, they tend to result in lower customer response than critical peak pricing, and baseline usage can be difficult to determine with accuracy. Time-of-use rates do not require that the utilities pay customer credits and calculate complicated baselines. Many jurisdictions are exploring even more sophisticated rate designs, particularly for electric vehicles. These options, and methods for developing time-of-use rates, are discussed in the following sections.

Time-Varying Rates to Promote Efficient Solar Deployment

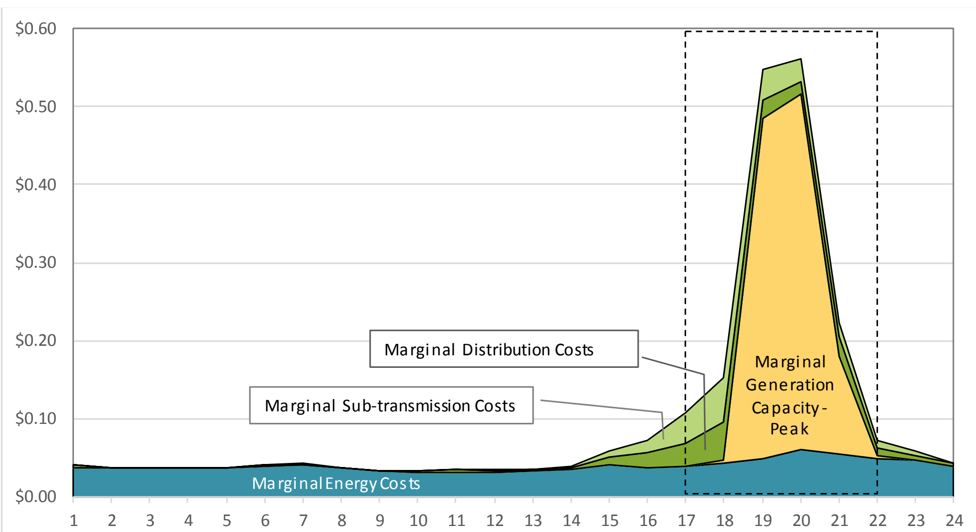
Rooftop solar systems are typically installed to be south-facing in order to generate the greatest quantity of energy, but not necessarily to generate energy when it is needed most. South-facing systems generate the most electricity in the middle of the day. In contrast, peak demand on Pepco's system (and at many other utilities) tends to occur later in the day, typically in the late afternoon or early evening hours. Thus, to provide the greatest load relief, it would be beneficial for rooftop solar installations to be oriented in a westward direction, even though this would reduce the quantity of energy produced.

California is currently grappling with excess solar generation during the mid-day hours, but large ramping needs in the early evening as solar generation falls off. West-facing solar could help mitigate the rapid decline of solar generation by extending the generation period slightly. To encourage solar generation to be sited more efficiently and to improve the accuracy of net metering compensation, new net metering customers will be required to take service on time-of-use rates.[200]

California's methodology for developing time-of-use rates takes into account time-varying marginal costs of generation capacity, energy, and distribution. At the distribution level, individual costs components are functionalized between grid and peak costs, where peak "refers [to] the distribution system's peak capacity function in meeting time-variant peak customer demand," and grid "refers to the distribution system's function that enables the bi-directional transfer of energy to and from customers."[201] The marginal costs are then summed to determine TOU peak periods.

Southern California Edison's (SCE) estimated hourly marginal costs are projected for the summer months of 2021 in the figure below. SCE's proposed TOU periods would shift the on-peak period four hours later to 4 pm to 9 pm, since net load is moving later in the day with the adoption of greater quantities of solar energy. In the winter, SCE proposes to include a "super-off-peak period" from 8 am to 4 pm to better accommodate renewable overgeneration and avoid the curtailment of renewable resources.

Figure 5. Hourly marginal costs for determining peak periods



The Solar Energy Industries Association (SEIA) generally supported SCE's methodology, but was critical of SCE's exclusion of marginal transmission costs. If included, SEIA argued, the marginal transmission costs would cause the peak to be shifted slightly earlier in the day. In addition, SEIA advocated the use of "Discount Days" instead of a winter super-off-peak period, arguing that renewable overgeneration

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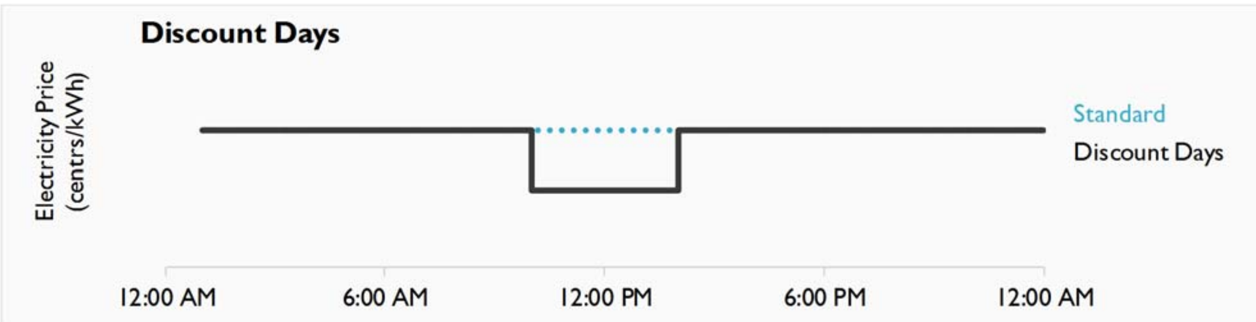
200 CPUC, "D.16-01-044, Decision Adopting Successor to Net Energy Metering Tariff," Rulemaking 14-07-002, Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering., February 5, 2016.

201 Southern California Edison, "Phase 2 of 2018 General Rate Case Marginal Cost and Sales Forecast Proposals, Exhibit SCE-02," June 30, 2017, 33.

conditions are not present every day, and thus a more targeted Discount Days pricing would be more appropriate. The Discount Days pricing would essentially be the inverse of a critical peak pricing program. Instead of a period of exceptionally high prices, customers would be offered discounted prices during the midday period for a limited number of event days (called in advance).[202] Figure 6 illustrates how the Discount Days program might be implemented, in which the midday hours during an event day have lower prices than the rest of the day.

Figure 6. Example of a discount days price structure



Finally, SEIA raised concerns regarding the bill impacts of SCE's proposed TOU period change for existing TOU customers who may have made invested in energy efficiency and distributed generation in response to the current TOU periods. Changing the start of the peak period to four hours later in the day than the current peak period start would have adverse bill impacts on current TOU customers, particularly those who have installed solar. SEIA points to bill impact data which shows that 30 to 40 percent of certain medium and large customers will experience bill increases of over 10 percent due to the proposed TOU periods.

Rate Design for Electric Vehicles

EVs have several notable characteristics that make them anomalous consumers of electricity. First, EVs can impose large demands on the system when charging, which needs to be properly accounted for during EV tariff design, to ensure that EV charging does not exacerbate peak demand and drive up system costs. Second, because EVs are effectively energy storage devices, they are a type of distributed energy resource that can provide services to the grid. Because the electricity stored in the EV is oftentimes not needed by the owner immediately, it becomes more palatable to promote efficient charging practices where charging is shifted away from peak periods.

Traditional rate design structures – e.g. time-invariant rates and the use of demand charges for commercial and industrial customers – do not promote efficient EV charging patterns, and provide no additional cost savings to promote the adoption of EVs. A time-invariant rate structure sends misleading

[202] Tom Beach, "Prepared Direct Testimony of R. Thomas Beach on Behalf of the Solar Energy Industries Association," A.16-09-003, Application of Southern California Edison Company for Approval of Its 2016 Rate Design Window Proposals, September 1, 2016.

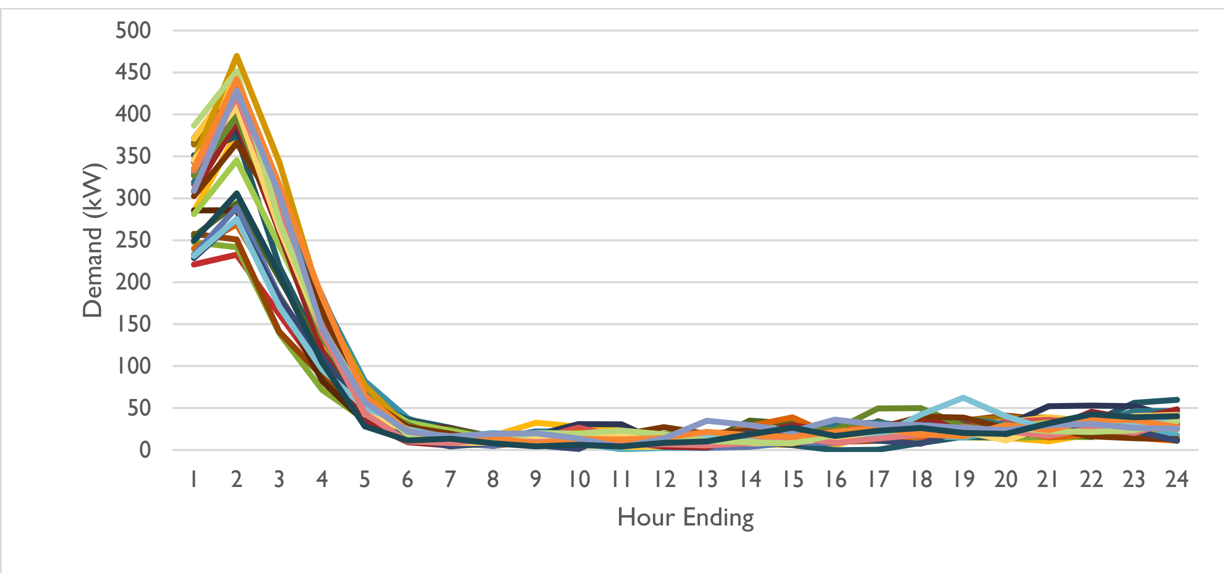
price signals to customers than a kilowatt-hour of energy costs the same amount regardless of when it is generated and consumed. As noted earlier, EV owners generally do not care when their vehicle is charged, so long as it is charged when they are planning to use it. Thus, the use of time-varying rates can incentivize EV owners to shift their charging practices to off-peak periods. In addition, time-varying rates can help to make EVs more affordable by providing the option to charge during low-priced off-peak hours.

Several utilities have explored time-varying rates designed specifically for EVs. San Diego Gas & Electric has been at the forefront of such initiatives, having already implemented two EV TOU rates for residential customers, a dynamic pricing pilot for commercial customers, and introducing several new rate design proposals for a wide variety of customers.

SDG&E's residential EV-TOU rate is "[a] rate for just your EV."[203] This rate requires the EV owner to install a separate meter for their vehicle, and it tracks the vehicle's electricity consumption separately from the house's.[204] The other current residential EV rate – EV-TOU-2 – is "[a] rate for your house & EV." This rate uses the meters already installed at customers' houses to track the combined home and EV electricity consumption. Both EV-TOU and EV-TOU-2 include super off-peak periods from midnight to 5 AM, a period of low system demand that is convenient for EV charging.

Consumption data from SDG&E's EV customers demonstrate that TOU rates have been effective at encouraging customers to shift EV load to off-peak periods. For example, the figure below shows the aggregate load of customers on SDG&E's EV TOU rate for each day of July 2016:

Figure 7. SDG&E's EV TOU load profile (July 2016)



[203] See: https://www.sdge.com/clean-energy/ev-rates.

[204] SDG&E also offers a rate which uses submetering via the meter embedded in the electric vehicle supply equipment.

The data shows that aggregate EV charging during July 2016 happened overwhelmingly overnight.

Despite the many benefits of TOU EV rates, it is important to be cognizant of potential unintended consequences during the rate design process, such as:

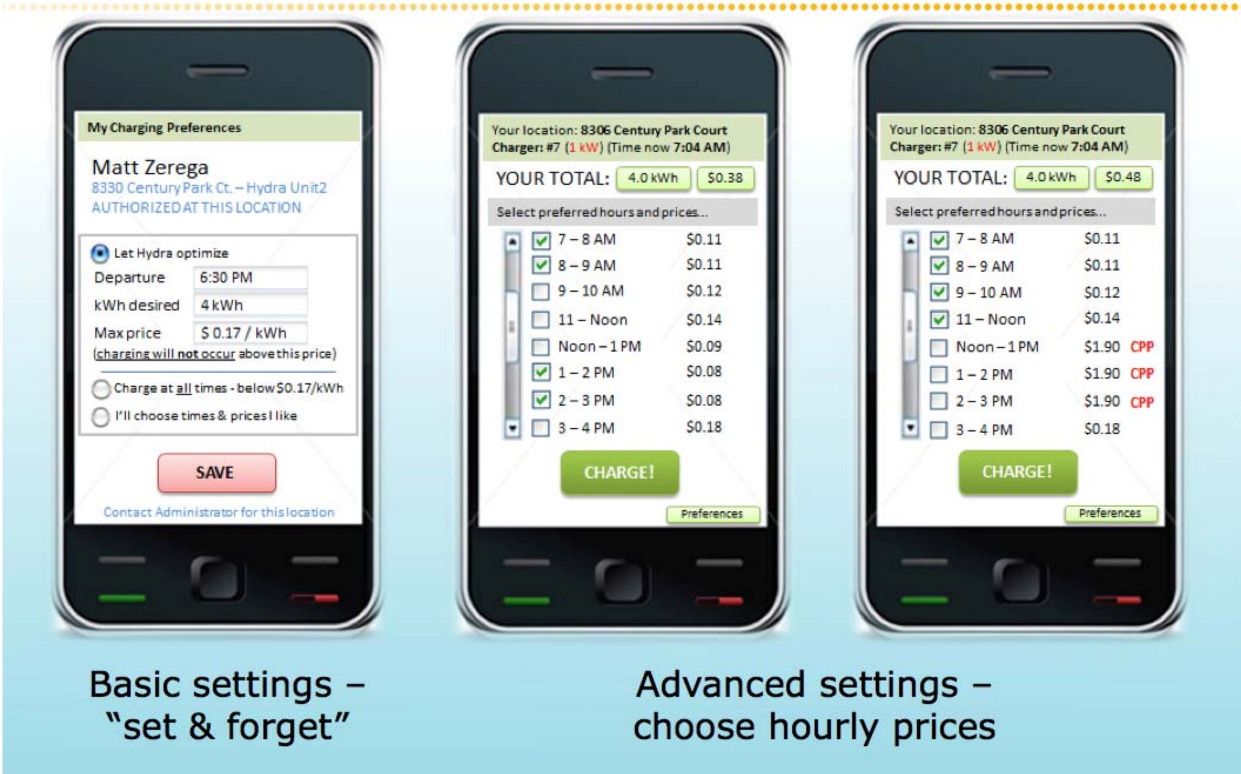
1. Creating new demand peaks in neighborhoods with many EV owners, thereby increasing congestion and system costs in those areas;
2. Discouraging the purchases of EVs or the switch to EV rates by requiring the installation of new, advanced meters to measure EV electricity consumption, or requiring that the TOU rate also apply to a customer's household usage, rather than just the EV;
3. Failing to keep up with changing load profiles and generation cost profiles, changes which could result in TOUs incentivizing charging during more costly periods.

Dynamic Pricing and Locational Peak Pricing

While TOU rates can be effective at sending general price signals to customers, dynamic pricing – a rate structure in which electricity prices can vary hourly or even more granularly – is better able to reflect the real-time price of electricity at any given time. The pairing of dynamic pricing schemes with automated charging infrastructure can allow EVs to charge at optimal times (by considering and responding to electricity prices and system demand in real time). However, local distribution system peaks do not always align well with system peaks, and it is important to ensure that time-varying rates do not send perverse price signals that exacerbate local system constraints. For this reason, some utilities are moving toward locational pricing.

San Diego Gas & Electric is again at the forefront of exploring these types of rate structures. The 2016 Vehicle-Grid Integration (VGI) Pilot Program – also known as Power Your Drive – will implement hourly dynamic prices that more appropriately signal the price of electricity generation at that time. The prices will be posted on an SDG&E website the day before they are in effect, and will consist of two components: a distribution component and a wholesale price component. The distribution component seeks to prevent the creation of new, EV-induced, localized demand peaks that poorly designed TOU rates can unintentionally create. The program will feature a smartphone app that allows customers to match their preferences regarding charging times and electricity prices with the available price information (see Figure 8 for an example of the app's interface).

Figure 8. Example interface of SDG&E's EV smartphone app



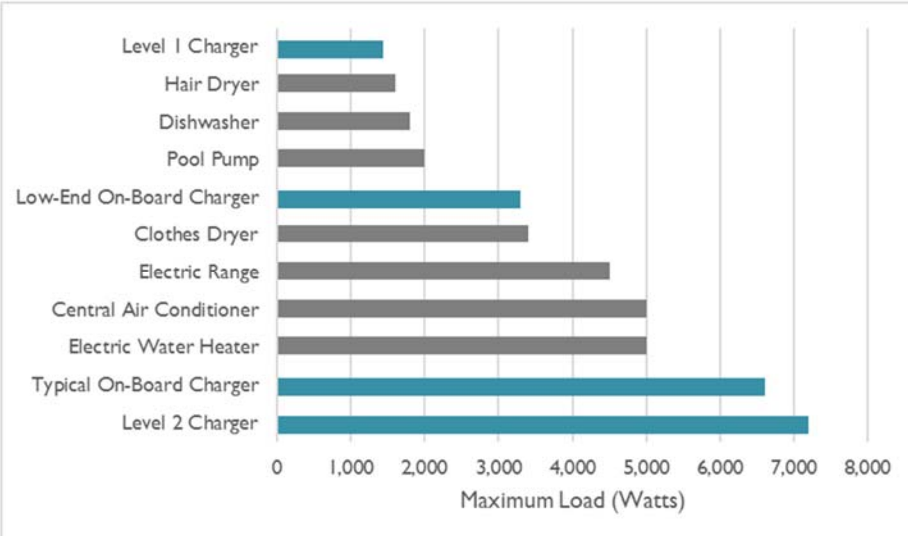
It should be noted, however, that while dynamic rates may be well-suited to EVs, which tend to have the technology to automatically manage usage, dynamic rates are less suited to typical residential customers who have limited ability to automatically monitor and control their energy usage in response to constantly-changing prices.

Ditching Demand Charges

Demand charges are often included in commercial and industrial rate designs. A demand charge is a per kilowatt charge that is linked to a customer's maximum demand during a set period, generally a month. For example, if a customer uses a maximum demand of 2 kW in an hour during that month, they will be charged a per-kW price for those 2 kW of maximum demand.

EVs tend to increase customers' demand substantially, particularly for residential customers with Level 2 chargers, which charge at approximately 7 kW. The figure below provides a comparison of the demand of various household appliances relative to a basic Level 1 charger and a more rapid Level 2 charger.

Figure 9. Typical household appliance demand and EV chargers



Because of the high demand imposed by a Level 2 charger, demand charges can heavily penalize customers who install EVs, even when not justified on the basis of cost causation. Demand charges discourage spikes of energy use; however, most demand charges do so without taking into consideration when the spikes occur. A non-coincident demand charge – that is, a demand charge that is not tied to a system or circuit peak – imposes a demand charge even when demand on the system is low, and charging imposes no additional demand-related costs on the grid. In addition, a demand charge encourages the smoothing out of a customer's demand, which could have the unintended consequence of shifting some of the demand to periods of system or circuit peaks. Further, the inclusion of demand charges can discourage businesses from installing EV charging stations to avoid the increased demand that comes from EV charging.

Demand charges can be especially challenging for public fast charging stations where the customer-of-record and the end-user are not the same. In such cases, rates that are not purely volumetric make it difficult for the customer-of-record to recover electricity costs from itinerant EV drivers, particularly when it is not know in advance how many EV drivers will visit a charging station. This is especially important in the early days of EV infrastructure where owners of public charging stations face high installation costs, but relatively few users.

In response to the high costs imposed by demand charges on EV customers, several utilities are abandoning demand charges for certain customers. For example, since July 2013, the Hawaiian Electric Companies (Hawaiian Electric, Hawai'i Electric Light, and Maui Electric) have offered a pilot EV tariff under the DC Fast Charger program called EV-F. Separately metered public EV charging stations are eligible for EV-F if their demand does not exceed 100 kW. The rate was implemented in response to the increased desire and demand for fast charging stations over Level 1 and Level 2 charging stations, and to make it easier for companies to provide public fast chargers. The tariff structure is as follows:

Table 5. Hawaiian Electric Companies' commercial EV tariff

Tariff		Priority-Peak	Mid-Peak	Off-Peak
EV-F	*Time of Day*	5 - 9 PM, M-F	7 AM - 5 PM, M-F 7 AM - 9 PM, Sat-Sun	9 PM - 7 AM, Daily
	$/kWh	$0.32	$0.30	$0.27

The rate structure discourages fast charging during priority-peak hours from 5 – 9 PM on weekdays and instead encourages faster charging during off-peak evening and early morning hours. In addition to the TOU energy rates, there is a $5 monthly metering charge. Noticeably absent is a demand charge, which can discourage the proliferation of EVs and fast charging infrastructure.

While developing EV-specific rate structures, Pepco should be mindful to consider the intended consequences of demand charges (e.g. load shifting) and be careful to avoid unintended consequences (e.g. disincentives for individuals and companies to install charging infrastructure).

Locational Value of DERs in New York

The ability of a resource to avoid or defer distribution system investment needs is largely dependent upon where the resource is located within a distribution system. To encourage efficient siting of DERs, price signals "must offer the information and incentives that DER providers need to locate, size, and design their projects based on the benefits and costs that will result from a particular DER interconnected in a particular location."[205]

To provide more accurate price signals, New York is transitioning away from static pricing (e.g., net metering) to dynamic tariffs for DERs that seek to better capture the timing, location and performance value associated with DER. These tariffs are referred to as "Value of DER" or "VDER" tariffs, and will capture traditional avoided costs such as energy, capacity, transmission and distribution and environmental values, as well as the locational value of siting the resource in a particular area on the distribution system.

The locational value associated with DER is referred to as the "Locational System Relief Value" and is based on a deaveraging of utility marginal cost of service studies during the 10 peak hours. Locational System Relief Values are intended to encourage DERs in areas where the value of avoiding transmission and distribution investments is high. To provide adequate revenue certainty for DER developers, a project's Locational System Relief Value will be fixed for ten years following interconnection.

Each of the New York utilities filed their proposals to establish Locational System Relief Values in spring 2017. The most common methodology for establishing Locational System Relief Values involved deaveraging the utilities' marginal cost of service values such that the Locational System Relief Value is

[205] New York Department of Public Service, "Staff Report and Recommendations," Case 15-02703, In the Matter of the Value of Distributed Energy Resources, October 27, 2016, 5, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={59B620E6-87C4-4C80-8BEC-E15BB6E0545E}.

50 percent higher than the system-wide value of reducing demand. However, Central Hudson developed a detailed stochastic load forecast model to establish new location-specific transmission and distribution values.

As a replacement for traditional net metering, the Value of DER calculated through this process will play an outsize role in determining the economics of deploying distributed generation and storage, and therefore the growth of these technologies. Unfortunately, it is not clear that the utilities' methodologies accurately accounted for the value that DERs can provide to the grid. For example, stakeholders raised concerns that two utilities' proposals calculated avoided distribution costs based only on investments related to load growth, rather than also considering the potential for DERs to help extend the life of existing infrastructure or avoid investments in a wider range of infrastructure. In addition, numerous questionable assumptions were made when developing granular system costs. For this reason, NRDC and other clean energy advocates have emphasized the need for these values (including the marginal cost of service studies underpinning them) to be reviewed in a litigated case with the opportunity for full discovery.[206]

New mass-market on-site DER projects will generally be eligible for the VDER Phase One Tariffs through January 1, 2020 or the issuance of a Commission order addressing such projects, whichever is earlier. In establishing the Phase One methodologies, the Commission recognized that initial values "would represent an imperfect proxy reflective of the limitations of currently available information, and accepted this as an initial step in the evolution from existing compensation methodologies to the fully distributed and transactive grid of the future."[207] Refinements to the VDER methodology, including standardization amongst utility approaches, are being contemplated in Phase Two.[208] New York's approach to more accurately compensating customers for the value that they provide to the grid promises encourage customers to develop DERs in a manner that provides the most benefit to the system, while also advance equity principles, since DER credit values are better aligned with economic values.

3.4. Utility Outcome-Based Incentives

Traditional cost-of-service regulation is not well-suited to supporting a more distributed energy future, or one that effectively addresses customers' evolving needs. Such concerns have motivated communities such as Boulder, Colorado and Winter Park, Florida to municipalize. However, innovative utility regulation is increasingly being used to provide utilities with incentives that better align with jurisdictions' policy goals.

[206] Miles Farmer, "New York Stumbles in Finalizing Value-Based Solar Credits," NRDC Expert Blog, September 18, 2017, https://www.nrdc.org/experts/miles-farmer/new-york-stumbles-finalizing-value-based-solar-credits.

[207] NY PSC, Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters, No. 15- E- 0751 and 15- E-0082 (September 14, 2017).

[208] NY PSC, Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters.

Under the traditional regulatory paradigm, there are several financial incentives that work against distributed energy resources. In particular, the cost-of-service framework provides utilities with a strong incentive to build rate base, as utilities earn a return on such investments.[209] Further, under traditional ratemaking, utilities tend to be reluctant to invest in new, untried, or innovative technologies, because of risks associated with post-investment prudence reviews.

Performance incentive mechanisms (PIMs) offer an option for addressing some of the traditional disincentives to DERs and to encourage utilities to achieve specific policy goals (such as customer empowerment and choice). Many jurisdictions already have a set of PIMs addressing conventional areas of utility performance (particularly reliability and customer service), but only a few have begun to introduce new measures of utility performance, including the use of DERs and customer empowerment.

With PIMs, regulators typically identify key areas of performance of interest, establish metrics for measuring and monitoring the performance, provide targets for the type of performance expected, and provide clearly defined financial incentives for achieving the targets. For example, regulators might dictate the type and magnitude of DERs that a utility should implement (as with energy efficiency), or a performance goal to be met using DERs (such as peak load reductions).

LILCO's poor storm response drove municipalization on Long Island, and a well-designed PIM associated with resiliency might have incented better planning and operations by LILCO. PIMs may have been a tool that could have helped address Winter Park's dual concerns of reliability and tree maintenance. Similarly, a PIM associated with fast response times to outages may have resulted in the IOU maintaining service positions within Jefferson County, thereby satisfying that community's desire for local jobs.

Key Issues to Address in Designing Performance Incentive Mechanisms

There are numerous considerations when establishing performance incentive mechanisms and associated financial incentives. While a detailed examination of these considerations is beyond the scope of this report, the following examples are worth highlighting:

- Which performance areas should be addressed? Potential areas include system efficiency, distributed energy resources, grid modernization investments, and environmental goals. These areas should be tied to the jurisdiction's energy policy goals.
- How large should financial incentives be? The size of the financial incentive should be tied to several factors:
    - Importance of the outcome. Those initiatives and outcomes that are especially likely to help achieve policy goals may warrant greater financial incentives than those with less of an impact on those goals.
    - Benefit-cost analyses. Initiatives and outcomes that are expected to be especially cost-effective might warrant greater financial incentives than those

[209] This incentive exists when the utility's rate of return exceeds the weighted average cost of capital.

that are less cost-effective. Also, any financial incentive should be less than, and ideally a reasonable portion of, the net benefit of the initiative or outcome being incentivized.

- Countervailing financial incentives. In general, utilities have a financial incentive to make capital investments that will increase their rate base and result in higher amounts of authorized profits. DERs can reduce the need for utility capital investments, and thus potentially reduce utility profits. The financial incentive should be designed to help offset the financial disincentive for DERs.
- Design or structural issues of the PIM. Some PIMs are difficult to measure or have outcomes that are difficult to verify. In such cases, a small financial incentive may mitigate the risk of over- or under-compensating the utility.
- Ability of the utility to control the outcome. Those initiatives and outcomes that are well within the control of the utility might warrant greater financial incentives than those that are not.
- Double-recovery. Often utility initiatives can influence a variety of outcomes. If certain outcomes are covered by more than one PIM, then those PIMs might warrant relatively small financial incentives.

- How should metrics be defined? Metrics should be defined clearly, be easily measured, and easily interpreted.
- How should targets be set? Sufficient data should exist to allow regulators to set targets that are reasonably attainable, but represent an improvement over what would otherwise be expected. The sources of such data can be historical utility performance, peer groups, or special studies.

Most PIMs in place in the United Sates today only provide financial incentives for a small number of performance areas, and therefore have a small impact on the utility's overall financial performance. To have a meaningful impact on a utility's incentive to build rate base, it may be necessary to establish significant, financial incentives to be awarded through PIMs. If the financial rewards available from PIMs are large enough, they can replace a portion of revenues that would otherwise be provided to the utility from its return on rate base.

New York

As part of REV, the New York Public Service Commission is addressing utility regulation, and the changing role of utilities in the provision of electricity services. To facilitate the utilities' transition to a new role as "platform service providers," the Commission has recognized that the utilities will require new earnings opportunities to replace or offset the incentives inherent in the traditional capital investment model. There are two avenues by which New York plans to provide performance incentive mechanisms:

1) Financial incentives for non-wires alternatives, and

2) Policy-driven outcome-based incentives, referred to as "Earnings Adjustment Mechanisms."

Financial Incentives for Non-Wires Alternatives

To encourage utilities to undertake non-wires alternative projects, the New York Commission has experimented with several financial incentive approaches over the past few years, two of which we describe below. The Commission has not yet finalized the form of financial incentives for its new NWA process, but will likely draw heavily from these examples.

The first example is the Pomona DER Program, which was approved in October 2015. The program stemmed from a joint proposal by Orange and Rockland Utilities to implement a non-wires alternative designed to defer the construction of the Pomona Substation and associated 138 kV underground transmission loop by four years using DERs.[210] Under the program, the utility may recover the total program costs (including customer incentives, capital investments, maintenance and labor) over a ten-year period through electric base rates up to $9.5 million in 2014 dollars. The Company defers the difference between the rate allowance of $380K per year and the actual revenue requirement. The Company is also allowed to apply a rate of return on any deferred Pomona DER program costs through a carrying charge at its authorized pretax weighted cost of capital.

In addition to allowing cost recovery with a return, the Pomona DER program provides the Company with the opportunity to earn an incentive of up to 100 basis points return on equity on the program costs when certain performance objectives are met:

- Cost Savings for each 1% reduction in cost per MW compared to the cost of the proposed Pomona Substation (1 basis point per 1% reduction, up to 50 basis points); and
- Amount of load reduction achieved above 3.0 MW (1 basis point for each 0.1 MW over 3.0 MW, up to 50 basis points)

The second example is the famous Brooklyn Queens Demand Management program. As noted in previous sections, this program was proposed by ConEd to defer a new substation and related investments with a lower-cost portfolio relying heavily on DERs.[211] As described in Synapse's 2015 report *Utility Performance Incentive Mechanisms: A Handbook for Regulators*,[212] the Commission approved several cost recovery and financial incentives for ConEd, including:

- A regulated return on the alternative investments,

[210] NY PSC, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service, October 16, 2015.

[211] NY PSC, "Order Establishing Brooklyn/Queens Demand Management Program."

[212] Melissa Whited, Tim Woolf, and Alice Napoleon, "Utility Performance Incentive Mechanisms: A Handbook for Regulators" (Synapse Energy Economics, March 9, 2015), http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

- A 10-year amortization period for the investments,
- A 100 basis point ROE adder on BQDM program costs tied to the achievement of specific outcomes related to achieving a certain capacity of alternative measures, increasing diversity of distributed energy resource vendor market, and implementing a portfolio that has a lower cost than the traditional solution. These performance incentives include Quantity of Alternative Measures, Diversity of DER Vendor Marketplace, and Reduction in $/MW Costs. [213]

The adoption of the above performance incentive mechanisms provides a clear signal to New York's utilities that distributed energy resources should be valued in a manner similar to traditional investments, and that reducing costs for consumers will be rewarded. The three performance incentive mechanisms (quantity of alternative resources installed, diversity of market, and cost) simultaneously address several of the commission's objectives. The incentive formula established by the Commission ensures that the Company will only be rewarded if it installs the amount of alternative resources required (41 MW), but will not be rewarded more for installing more resources than needed, thereby avoiding an incentive to procure excessive amounts of alternative resources.

Despite its strengths, two aspects of the performance incentive mechanism have been criticized: (1) the linkage between rate base and the financial incentive, and (2) the definition of the diversity index.

First, the financial reward's direct link to rate base (through virtue of being an ROE adder) means that increasing rate base will in turn increase the Company's financial reward, which may exacerbate utility incentives to increase rate base.

The second issue concerns the diversity index definition. This metric was proposed as a normalized entropy index, calculated as follows:

$$normalized\ entropy\ index = \frac{\sum_{i=1}^{N} S_i \ln(S_i)}{\ln(N)}$$

Where N is the number of DER Providers and S_i is the share, in MWh, of each provider in the selected portfolios.

The target was set at 0.75, with the maximum reward occurring at 1.0. The utility would be rewarded one basis point for each 0.01 increase in the normalized entropy index above the baseline (up to 25 basis points). However, as pointed out by ConEd:[214]

- The diversity index focuses on the number of vendors who are awarded contracts, but does not include direct customers and subcontractors.
- The definition of the diversity index does not measure diversity of technologies.

[213] NY PSC, "Order Establishing Brooklyn/Queens Demand Management Program."

[214] ConEd, "Petition for Rehearing and Clarification of Consolidated Edison Company of New York" (Consolidated Edison Company of New York, Inc., January 12, 2015), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={963D9EDC-0997-43D9-9796-C8496B26178B}.

- The specific calculation of the entropy index appears to reward equal contributions of capacity more than the number of vendors. That is, under the current metric definition, the Company would earn the maximum reward if two vendors each contribute 50% or if five vendors each contribute 20% of the capacity.

These concerns highlight the difficulty in defining performance metrics that accurately capture the outcomes desired, and that do not result in unintended consequences.

Earnings Adjustment Mechanisms

As part of New York's vision to move toward a more distributed grid, utilities will be required to work closely with third parties, including DER providers, and support customer adoption of DERs. The Commission has recognized that utilities should be provided with performance incentives and revenues to support utilities in this new role:

> To serve consumer requirements, utilities must be prepared to design and operate systems that are adaptable and supportive of third-party investments that increase both the system and economic efficiency of the fully integrated grid. System efficiency will require more cooperative and productive arrangements among regulated utilities, non-utility developers, and consumers. New earning opportunities will be a combination of outcome-based performance incentives and revenues earned directly from the facilitation of consumer driven markets.[215]

Such performance incentives are referred to "Earnings Adjustment Mechanisms" (EAMs), and are being established as part of each utility's rate case. At the time of writing, Niagara Mohawk's proposed EAMs were under review by stakeholders and the Commission. Table 6, below, lists Niagara Mohawk's proposed 14 EAMs, together with the Company's proposed maximum earnings associated with achieving the maximum target.

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[215] NY PSC, "Order Adopting a Ratemaking and Utility Revenue Model Policy Framework," Reforming the Energy Vision, May 19, 2016, 5–6.

Table 6. Niagara Mohawk's proposed earnings adjustment mechanisms

Earnings Adjustment Mechanisms Proposed by Niagara Mohawk	
Incentive	**Basis Points**
System Efficiency	
Annual Net Peak Reduction (MW)	30
Substation Load Factor	5
DER Utilization (MWh)	10
Energy Efficiency	
Incremental Energy Efficiency (MWh)	7
Energy Intensity (Residential)	10
Energy Intensity (Commercial)	10
Energy Intensity (Low-Income)	3
Interconnection	
Developer Satisfaction Survey	5
Customer Engagement	
DR Retention (Res & Small Bus)	1.3
DR Retention (C&I)	1.3
Customer Participation (Res)	1.3
Customer Participation (C&I)	1.3
Transactional Conversion Rate	2.5
Survey	2.5

Niagara Mohawk has proposed three EAMs within the category of System Efficiency:

- The Annual Peak Reduction EAM is designed to encourage the Company to reduce annual distribution system peak demand through a variety of initiatives, including energy efficiency programs, the direct load management programs, incremental energy efficiency driven by the Company's E-Commerce Platform, energy storage projects, grid modernization efforts like the deployment of volt-VAR optimization technology, and increased penetration of DER.[216]

- The Substation Load Factor EAM is designed to encourage the Company to improve the load factor at seven substations that (a) are currently highly utilized;[217] (b) lend themselves to accepting relatively high levels of DERs and connecting larger customers; and (c) have Supervisory Control and Data Acquisition (SCADA) capabilities for tracking and validating load information. The Company hopes to improve the average load factor

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216 Niagara Mohawk, "Electric Customer Panel," Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Electric and Gas Service, April 28, 2017, 46.

217 The Company notes that the selected substations have peak forecasts between 90 percent and 100 percent of the summer normal rating in 2017. Ibid., 48.

at these seven substations by targeting them with demand response, other demand-side management technologies, storage solutions, and distributed solar technologies.[218]

- The DER Utilization EAM is designed to encourage the Company to promote the development of DERS in general throughout its service territory. This EAM does not include the impacts of the Company's demand response activities, nor does it include the impacts of the Company's energy efficiency programs. Instead, it covers the development of technologies such as distributed solar, energy storage, combined heat and power (CHP), fuel cells, and electric vehicles. The Company intends to promote these technologies through collaboration with third parties.[219]

The energy efficiency EAMs consist of two types of targets:

- The Incremental Energy Efficiency EAM is designed to encourage the Company to exceed the minimum energy savings targets of its efficiency programs. Niagara Mohawk intends to exceed these targets through collaborative efforts with NYSERDA and local governments, as well as program cost savings through improved performance and market innovations.[220]

- The Customer Energy Intensity EAM is designed to encourage the Company to reduce customer energy intensity in terms of usage per customer. Within this category, the Company has proposed three separate Customer Intensity EAMs, for residential, commercial, and low-income customers.

A single EAM related to interconnection was proposed:

- This EAM will consist of a developer satisfaction survey that is to be developed with stakeholder input.

Six customer engagement EAMs were proposed, largely focused on customers' use and satisfaction with various partnerships the Company has established with third party providers of DERs:

- The purpose of the Demand Response Retention EAM is to encourage the Company to keep customers enrolled in the Company's various demand response programs as long as possible.[221]

- The Customer Participation EAM measures the increase in the number of customers either making purchases or enrolling in programs through the E-Commerce Platform, the Residential Solar Marketplace, and the Company's direct load control programs.

[218] Ibid.

[219] Ibid., 50.

[220] Ibid., 53.

[221] Ibid., 60–63.

- The Transactional Conversion Rate EAM is designed to encourage Niagara Mohawk to increase the number of purchases that customers make, as a percentage of total visits, from the E-Commerce Platform or the Residential Solar Marketplace.
- The Customer Survey will measure satisfaction from customers who make purchases from the E-Commerce and the Residential Solar Marketplace.

While Niagara Mohawk's proposed EAMs represent a set of innovative metrics for measuring utility performance, they exhibit several shortcomings.

- First, the Company did not provide a cost-benefit analysis for each EAM, and thus it is unclear whether the financial rewards associated with each EAM are appropriate. As noted above, the cost-effectiveness of the outcomes (and the costs associated with achieving the outcome) should play a large role in determining the magnitude of the financial incentive for each EAM. It would be inappropriate to provide a financial incentive that mostly or entirely offsets the net benefits of the outcome for customers.
- Second, several of the EAMs, such as peak reductions, could be influenced by activities undertaken with other EAMs, as well as by external factors outside of the utility's control. For this reason, it may be reasonable to allocating a smaller incentive value to such EAMs.
- Third, certain metrics, such as station load factor, are indirect measures of performance and may result in unintended consequences. For example, because load factor is driven by both peak demand and energy consumption, the Company or customers could increase energy consumption to improve the load factor without decreasing the peak demand at all. Such an outcome might increase customer costs and increase carbon emissions, without providing the improved system efficiency that the Commission seeks. Similarly, the customer energy intensity EAM would provide a disincentive for the utility to support beneficial electrification, such as through high-efficiency heat pumps and electric vehicles. Therefore, such an EAM should not be implemented unless the effects of beneficial electrification are controlled for (i.e., removed from the calculation of energy consumption).

Data Dashboards

To facilitate performance monitoring and the development of performance incentive mechanisms, data should be regularly collected on various metrics (regardless of whether such metrics also have financial incentives.) Data dashboards can provide a means of collecting utility performance information in a central location and presenting the data in a transparent and meaningful way. Dashboards also allow data to be compared across years to determine trends in a utility's performance. If a performance target is set, the dashboards enable stakeholders to quickly determine whether the utility is meeting or failing to achieve the targets.

The California Public Utilities Commission recently launched a data dashboard website where it collects information on a variety of metrics, including customer satisfaction, customer engagement, and environmental goals performance.[222] Customer engagement measures levels of customer participation in programs such as:

- Energy efficiency
- Demand response (including customer receiving special rates to shift electricity usage during peak periods)
- Net metering
- Energy storage
- Electric vehicles
- Website portal visits (referred to as "information availability")
- Enrollment in time-of-use rates (referred to as "rate choices")

Data for 2016 are shown in the table below for each of the three large IOUs:

Table 7. California 2016 residential customer program participation metrics

Energy Efficiency (EE)	SCE	PG&E	SDG&E
% of **total customers** participating in customer direct EE programs*	2.7%	2.9%	1.7%
Demand Response (DR)	**SCE**	**PG&E**	**SDG&E**
% of **total customers** participating in DR programs	16%	4.7%	8%
Net Energy Metering (NEM)	**SCE**	**PG&E**	**SDG&E**
% of **total customers** participating in the NEM program	4.8%	5.2%	8.1%
Energy Storage	**SCE**	**PG&E**	**SDG&E**
% of **total customers** who have energy storage	0.001%	0.001%	0.002%
Electric Vehicles (EV)	**SCE**	**PG&E**	**SDG&E**
% of **total customers** who own an EV	2%	0.56%	0.67%
Information Availability	**SCE**	**PG&E**	**SDG&E**
% of **total customers** using online accounts to check their energy usage	N/A	9%	13%
Rate Choices	**SCE**	**PG&E**	**SDG&E**
% of customers on a time-of-use (TOU) rate	1.12%	4%	2.16%

* This participation rate includes only programs that engage customers directly. The majority of EE programs now work directly with manufacturers, distributors, and contractors to ensure that energy efficiency appliances are prioritized for customers. These programs are more cost effective and are also funded by ratepayers, but are NOT included in the figure above because those customer participation rates are tracked separately.

[222] The dashboard is hosted at www.cpuc.ca.gov/dashboard

4. Conclusions

On behalf of the District of Columbia Department of Energy and Environment, Synapse Energy Economics reviewed all successful municipalization efforts undertaken in the past several decades, with an in-depth focus on the municipalization history of Long Island, New York; Winter Park, Florida; and Jefferson County, Washington. These three communities were chosen because they represent communities larger than 10,000 residents and offered considerable diversity of size, challenges faced, and degree of success. The ongoing municipalization efforts of Boulder, Colorado were included as well.

Although the anecdotes and data associated with these four communities may provide some insight regarding the process of municipalization, the outcomes of these four communities by no means represent the breadth of possible municipalization outcomes, nor does a successful approach taken by one community guarantee success for other communities.

Each of the four communities studied faced a specific and atypical challenge or objective. Because the municipalization process hadn't been undergone in decades, neither the communities, the incumbent electric utility, nor the legal or regulatory system was equipped to determine or present a clear process. The IOU from which the muni sought to separate vigorously opposed the efforts in two communities. The communities studying municipalization spent considerable funds and staff time on legal, engineering, and financial analyses. The communities relied on general municipal or state revenue, or in the case of Boulder, a specific tax to fund their due diligence and efforts.

Uncertainty wasn't limited to the legal process; laws detailing the asset valuation process were typically vague or inconsistent. Of the four asset valuation methodologies commonly associated with electric municipalization, original cost less depreciation and going concern were the methodologies most often referenced, although the final price for the assets in two of the three completed municipalization efforts were determined by arbitration or negotiation instead. In both of those cases, the finalized price was higher than the value the communities' studies indicated.

Of the three communities studied that have completed municipalization, all continue operating, with progress toward their initial goals varying considerably.

Utilities across the country are engaging in novel, creative, and high-tech approaches to meet evolving customer needs in a cost-effective, manner. These efforts include new approaches to planning and operating, the integration of electric vehicles in grid infrastructure and operation, innovative rate designs and tariffs, and outcome based performance incentive measures for the utilities themselves.

Increasing penetrations of EVs, dispatchable demand resources such as batteries, and two-way power flows due to customer-sited solar PV are all new challenges to utilities. They are also opportunities, though, as those resources can be used to reduce costs and improve reliability if deployed in the most beneficial locations. Two approaches to realize those benefits include distribution system planning at a fine granularity and using DERs as non-wires alternatives to location-specific distribution system challenges.

Electric vehicles are a necessary component of energy-consuming landscape if significant greenhouse gas reductions are to become a reality. Some utilities are embracing the growth of EVS as an opportunity, not just for increased sales but as a form of demand response. Charging infrastructure equipped with communication capability is allowing some utilities to directly shape the load associated with EV charging, and in doing so lower costs by shifting demand away from high-cost hours.

Rate designs and tariffs designed to take advantage of emerging technology and customer preferences are also becoming more common. For example, time-varying rates are being used to provide demand response, promote the efficient deployment of solar, and for managing EV charging to avoid costly generation, transmission, and distribution upgrades. Innovative tariffs such as New York's Value of DER tariff are allowing utilities to refine residential PV net-metering tariffs in a way that properly compensates customers while incenting deployment on the distribution system where the DERs will provide the greatest benefit.

Performance incentive mechanisms have historically been used to incent reliability and customer service, but are now being developed to provide incentives with respect to distributed energy resources. PIMs can be used to reward utilities for avoiding costly infrastructure improvements by instead deploying non-wires alternatives. PIMs can also be used to reward the utility for effective customer outreach resulting in increased voluntary participation in programs that lower cost or achieve public policy objectives.

Innovative utility practices, often associated with phrases like "utility of the future" or "GridMod," are being deployed throughout the country. Utilities and entire jurisdictions focused on meeting modern policy objectives and enhancing the quality of service to modern electric ratepayers are deploying a variety of innovative planning, infrastructure, rate making, and compensation schemes.

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