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Preliminary Feasibility Study
City of Pueblo, Colorado Municipalization

September 2019

CONCENTRIC ENERGY ADVISORS

www.ceadvisors.com

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DEFINED TERMS

ABB	ABB EPM Advisors
APPA	American Public Power Association
BEPC	Basin Electric Power Cooperative
BHE	Black Hills Energy
BHE Option	The scenario in which BHE continues to provide electric service to its customers within Pueblo
City	City of Pueblo, Colorado
City Option	The scenario in which the City takes ownership and operation of the electric distribution system within the city limits
Company	BHE
Concentric	Concentric Energy Advisors, Inc.
CPUC	Colorado Public Utilities Commission
EPA	United States Environmental Protection Agency
EUC	Pueblo Energy Utility Commission
FERC	Federal Energy Regulatory Commission
Handy-Whitman Index	Handy-Whitman Index of Public Utility Construction Costs
IMPC	Indiana Michigan Power Company
JEA	Jacksonville Electric Authority
JPUD	Jefferson County Public Utility District No. 1
kWh	kilowatt-hour
LIPA	Long Island Power Authority
MWh	Megawatt-hour
NEM	Net energy metering
NPV	Net Present Value
O&M	Operations and maintenance
OATT	Open Access Transmission Tariff
PAGS	Pueblo Airport Generating Station
Preliminary Feasibility Study	The independent preliminary assessment by Concentric of the costs and implications of the City acquiring the existing electric distribution assets of BHE solely within the city limits and assuming responsibility for providing electric service to the Company's existing customers in the City
PPA	Power purchase agreement
PSE	Puget Sound Energy
PUD	Public Utility District
RCNLD	Reproduction Cost New Less Depreciation
RCN	Reproduction Cost New
San Isabel	San Isabel Electric Association
Tri-State	Tri-State Generation and Transmission Association
WECC	Western Electricity Coordinating Council
Xcel	Xcel Energy Inc.

QUALIFICATIONS

Concentric Energy Advisors, Inc. ("Concentric") is a management consulting and financial advisory firm focused on the North American energy industry. Concentric has offices in Marlborough, Massachusetts, Washington, D.C., Calgary, Alberta and Chicago, Illinois, and specializes in utility regulation, energy markets and resource planning, financial advisory including valuation, and litigation. In particular, Concentric has conducted numerous feasibility analyses throughout the United States, having been retained by both investor-owned utilities and municipalities to evaluate all aspects of municipalization.[1]

This report was prepared under the direction of Ann E. Bulkley, Senior Vice President and Toby Bishop, Senior Vice President.

Ms. Bulkley is a certified general appraiser licensed in the Commonwealth of Massachusetts and the state of New Hampshire. Ms. Bulkley has more than two decades of management and economic consulting experience in the energy industry. Ms. Bulkley has directed and supported numerous valuations of public utility and industrial properties for ratemaking, purchase and sale considerations, ad valorem tax assessments, and other accounting and financing matters. These valuations require expertise in utility finance and regulation, electricity and natural gas markets, and utility risk assessment. Prior to joining Concentric, Ms. Bulkley held senior expertise-based consulting positions at several firms, including Reed Consulting Group and Navigant Consulting, Inc., where she specialized in valuation. Ms. Bulkley holds an M.A. in economics from Boston University and a B.A. in economics and finance from Simmons College.

Mr. Bishop has over 20 years of management and economic consulting experience in the energy industry. Mr. Bishop's experience includes asset valuation, regulatory representation and litigation support, and assessments of energy markets. Mr. Bishop has conducted valuations of numerous energy assets throughout the United States and has extensive federal and state regulatory experience in the United States and Canada, including rate case proceedings, prudence reviews, project need, asset transfers, regulatory strategy and policy formulation. In addition, Mr. Bishop has assisted numerous clients in evaluating energy markets throughout the United States as part of asset valuations, due diligence, market power analyses and new development/expansion opportunities. Prior to the formation of Concentric Energy Advisors, Mr. Bishop consulted for several years with Reed Consulting Group and Navigant Consulting, Inc. Mr. Bishop has a B.A. in economics and geography from Colgate University.

[1] Neither Concentric nor any of its employees have any present or contemplated future interest in the assets analyzed in this report. Neither Concentric's engagement by BHE nor its compensation for such engagement is in any way contingent upon the value estimates contained in the Preliminary Feasibility Study.

EXECUTIVE SUMMARY

Concentric has performed an independent preliminary assessment of the costs and implications of the City of Pueblo, Colorado ("City") acquiring the existing electric distribution assets of Black Hills Energy ("BHE" or the "Company") solely within the city limits and assuming responsibility for providing electric service to the Company's existing customers in the City ("Preliminary Feasibility Study").[2]

The Electrical System

The electric system is comprised of three major components:

Generation	the power plants that produce electricity
Transmission	the towers and high-voltage wires that carry electricity long distances to cities and towns from the power plants
Distribution	the poles and wires on city streets that carry electricity to customers' homes

Generation **Transmission** **Distribution** **Customer**

Graphic: www.sparkyourpower.ca

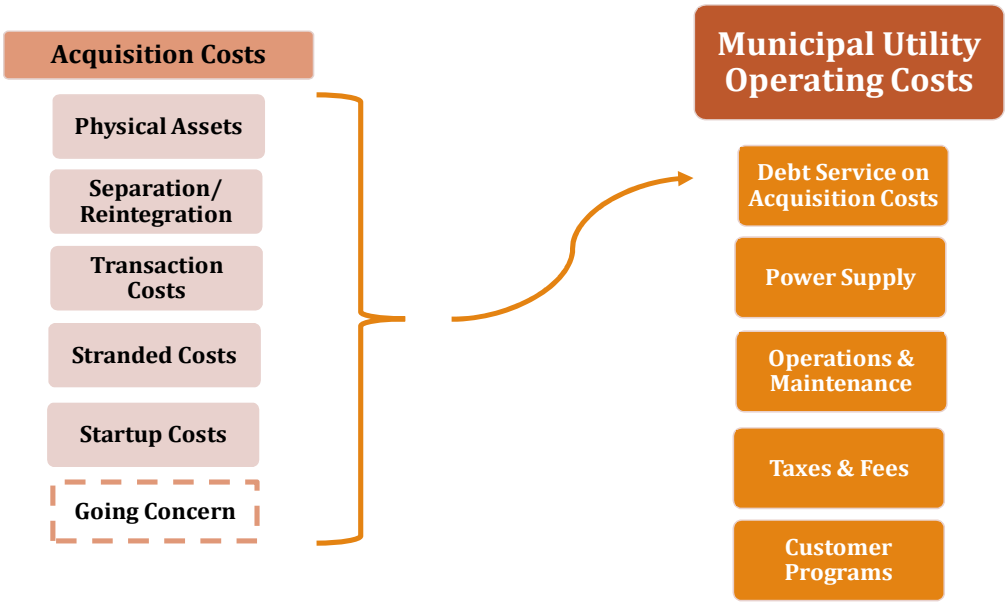
This feasibility study estimates the cost to the City of acquiring electric assets from BHE, establishing a new municipal electric utility and providing municipal electric service ("City Option") and compares that cost to the estimated cost of BHE continuing to provide electric service to the City ("BHE Option"). The estimated costs discussed herein ***do not*** reflect the City acquiring any of BHE's electric generation or transmission assets, nor any electric distribution assets outside of Pueblo.

[2] The information presented herein is on a preliminary basis and are not intended to represent the actual acquisition costs that would be paid by the City to BHE if the City were to form a municipal electric utility. All statements, assumptions, opinions, positions, and conclusions set forth in this report are solely and exclusively provided by and attributable to Concentric and to no other party. Concentric is solely responsible for the contents of the Preliminary Feasibility Study. Nothing in this Preliminary Feasibility Study is intended, nor shall be construed, to be information, admissions, statements, assumptions, opinions, positions, or conclusions made or provided by or on behalf of BHE.

A summary of the findings of the Preliminary Feasibility Analysis is as follows:

- The cost of the City Option is a function of (i) the debt service associated with the costs incurred by the City to acquire BHE's distribution system within the City; and (ii) the other operating costs to be incurred by the City to own and operate a municipal electric utility. Figure ES-1 identifies the categories of acquisition and operating costs that would need to be evaluated in the City Option.

Figure ES-1: Costs of Municipalization



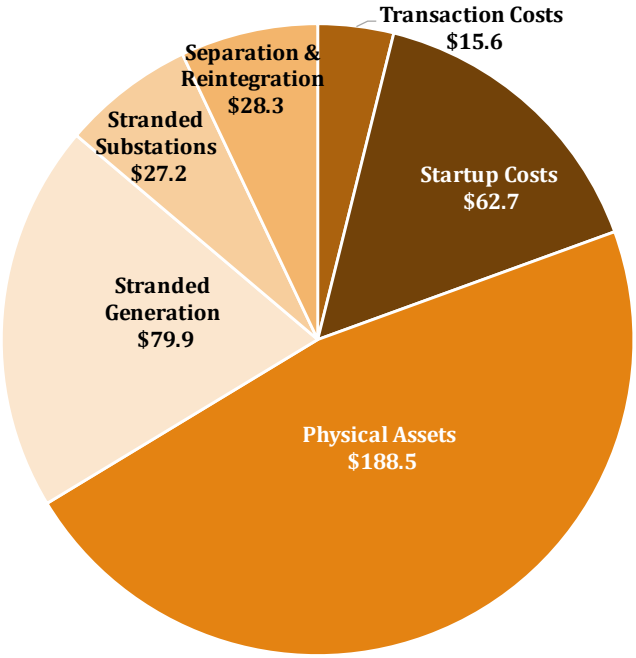
- Figure ES-2 shows the estimated initial capital costs for Pueblo to acquire the BHE electric distribution within the city limits and form a new municipal utility effective in 2024.[3]
- It is important to note that, as part of the approximately $402 million in estimated acquisition costs, there is ***no*** value assigned to the cost that the City may be required to pay BHE related to the value of the going concern.[4] To the extent a determination is made that the City would be required to compensate BHE for the value of the going concern, the additional cost could be

[3] It is important to recognize that this is a preliminary estimate that would need to be refined after a complete system inventory of the property that would be acquired is conducted and the impact of a municipalization on BHE's remaining customers determined. In addition, the estimated cost to acquire BHE's utility property in the City herein does not reflect any value associated with "going concern" that may be applicable if the City were to pursue municipalization.

[4] The value attributable to the going concern is the incremental lost value to BHE attributable to the fact that the distribution assets in Pueblo are not just a collection of physical assets but are part of a larger complete business unit that would not be as valuable after municipalization.

significant. For example, Xcel Energy has indicated that the going concern value could add $300 million or more to the acquisition value if the City of Boulder forms its own municipal utility.[5]

Figure ES-2: Preliminary Estimate of Acquisition Costs (City Option)
Electric Distribution System in Pueblo Only



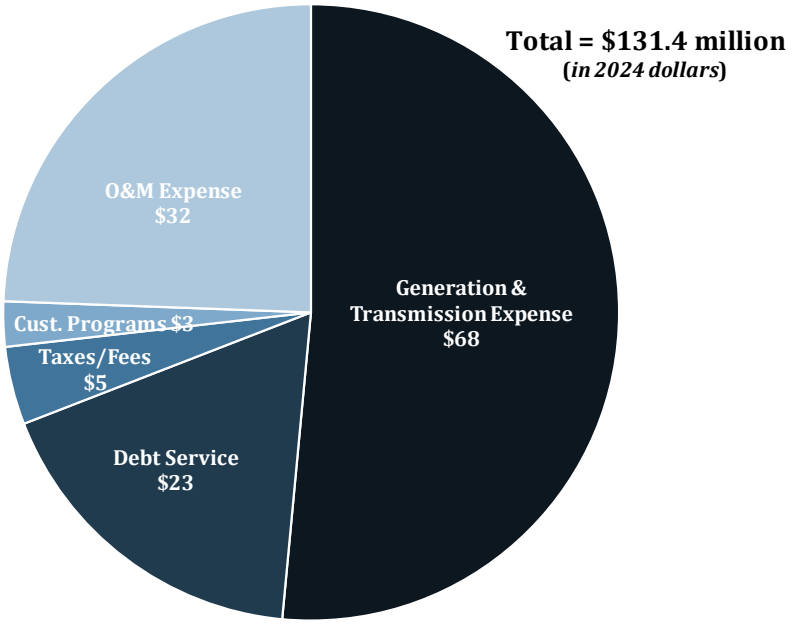
Total = $402.0 million
(*in 2024 dollars*)

Does not **assign a value to the Going Concern; which could be significant**

- If the City were to form a new municipal utility, the annual cost to the City of owning and operating a municipal utility would reflect both the debt service associated with the $402 million in acquisition costs, as well as the other required operating costs.
- As shown in Figure ES-3, the annual operating costs that would need to be recovered from customers in Pueblo under the City Option are estimated to be approximately $131 million starting in 2024.

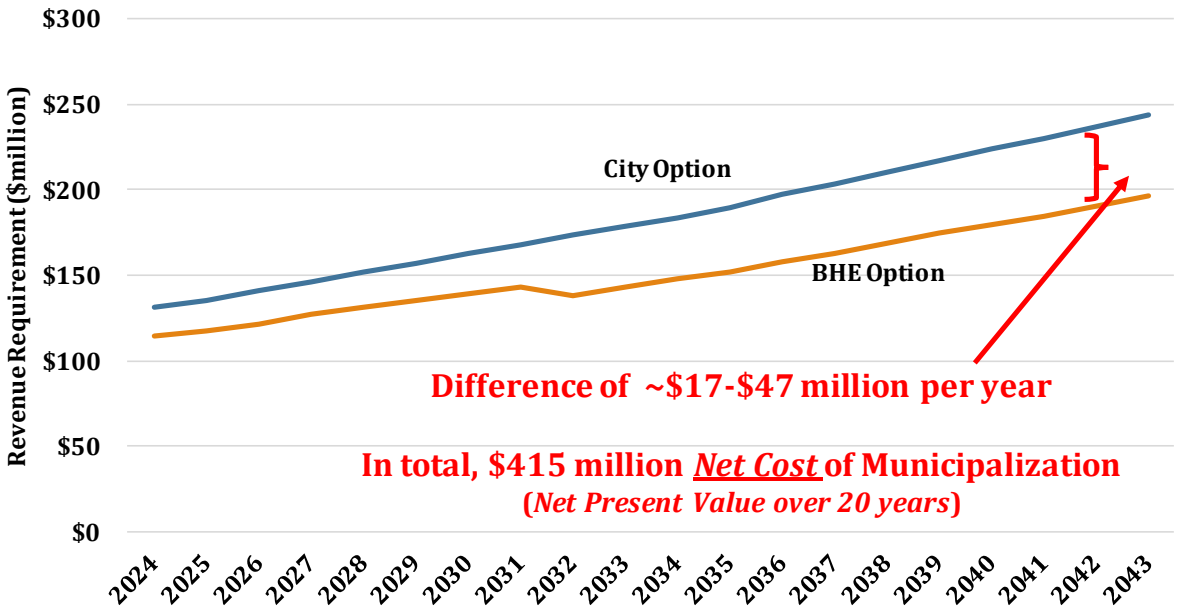
[5] *See, e.g.*, Dodge, Jefferson and Dyer, Joel, "Boulder's municipalization minefield," Boulder Weekly, February 28, 2013 ("Xcel officials estimate that the city will owe them $300 million in going concern costs…"); Energize Weekly, "Boulder's effort to create a municipal utility faces challenges at the ballot box and in the courts," October 25, 2017; UtiliPoint International, Inc., Boulder Feasibility Analysis, July 11, 2011 (indicating a possible going concern value of $350 million).

Figure ES-3: Preliminary Estimate of Year 1 Operating Costs (City Option)
Electric Distribution System in Pueblo Only



- To assess whether the City Option is economic, it must be compared against the estimated future cost of the BHE Option.
- Assuming BHE would have annual average rate increases consistent with its prior experience since acquiring the system in 2008, as well as the distribution rate experiences of other investor-owned electric utilities in the western U.S, it is estimated that the cost of BHE continuing to provide electric service in Pueblo would be approximately $114.5 million in 2024.
- As shown in Figure ES-4, the City Option is projected to be significantly more costly than the BHE Option. Specifically, it is estimated that the City Option would be approximately $17 million to $47 million per year more costly over the initial 20 years of municipal operation relative to the BHE Option. This equates to an estimated total ***net cost*** to the electric customers of Pueblo of $415 million (expressed on a net present value basis) over the initial 20-year period.

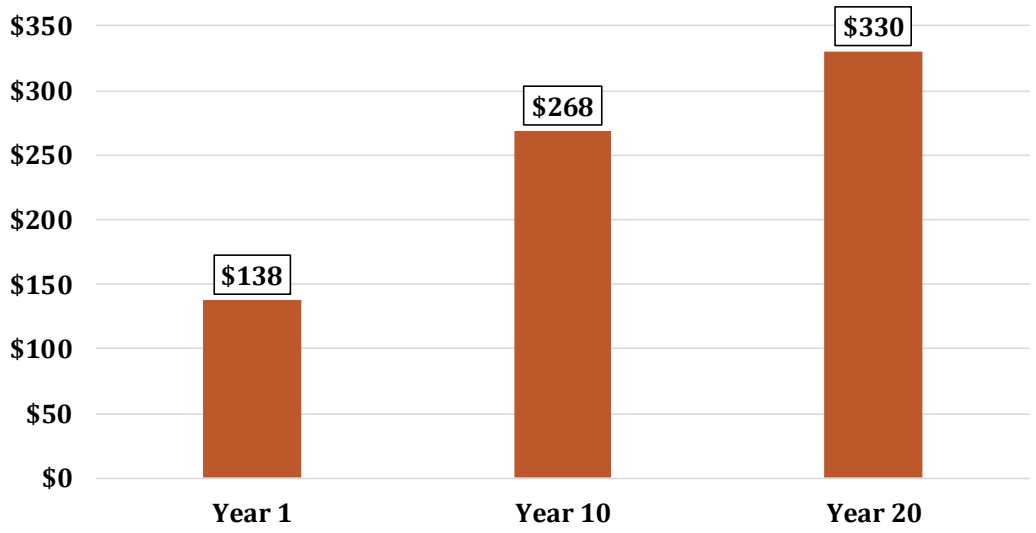
Figure ES-4: Projected Cost Comparison – City Option v. BHE Option



- Regarding Figure ES-4:
  - The projected cost of future electric service to Pueblo customers under the BHE Option decreases in 2032 upon the expiration of a large purchase power agreement ("PPA"). Due to the difference between the cost of energy purchased by BHE through that PPA and the projected market price of energy at that time, the expiration of the PPA creates a step-change reduction in the generation component of BHE's estimated total revenue requirement in 2032.
  - The projected cost of future electric service to Pueblo customers under the City Option reflects the market price of power that could be purchased by the City, and also reflects the costs the City would pay to compensate BHE for generation investments made to serve Pueblo that would no longer be needed by Pueblo (*i.e.*, stranded generation). For this study, stranded generation costs are determined at the time of the City's acquisition of BHE's electric distribution system and financed over a 30-year period, thus resulting in no similar step change in the estimated future cost of the City Option when the PPA expires.
- The Preliminary Feasibility Study estimates a net cost to the City if it were to form its own municipal utility, which would result in customers paying more under the City Option relative to the BHE Option. Figure ES-5 presents the estimated additional annual cost to the average residential electric customer in Pueblo if the City were to form its own municipal utility.[6]

[6] The average bill increases reflect the additional cost of municipalization as estimated in this Preliminary Feasibility Study divided by the total usage in Pueblo, then multiplied by the average usage of a residential customer in Pueblo over the past five years.

Figure ES-5: Estimated *Annual Average* Bill Increase for Residential Customers If Pueblo Were to Form Its Own Municipal Utility



- Two additional scenarios are developed to reasonably bound the results of the feasibility analysis and provide insights into the range of potential outcomes from establishing a municipal electric utility. These scenarios use unbiased market data to estimate lower and higher cost assumptions for the City and BHE and result in low and high operating cost scenarios for the City Option. These scenarios highlight two key points:
    - Even under a scenario in which the acquisition and operating costs under the City Option are assumed to be lower and the future BHE rate is assumed to be higher, there is projected to be a substantial net cost to Pueblo of municipalization over the first 20 years of operation relative to continuing service with BHE.
    - If the assumed acquisition and operating costs to the City are at the higher end of the estimates and the future BHE rate is at the lower end of the estimates than assumed in the base case, there is the potential that Pueblo electric customers could end up paying over $800 million dollars more (on a net present value basis) than if the City were to continue service with BHE over the initial 20-years of municipal utility operation.
- It is important to note that the acquisition and operating costs for the City Option shown in Figures ES-2 and ES-3 ***exclude*** a number of key factors:
    - The Preliminary Feasibility Study does not assign a value to the going concern , which would most likely be subject to litigation. However, if it is determined through subsequent litigation that the City is required to compensate BHE for the value attributable to the going concern in addition to the Pueblo electric utility assets, the cost to the City to acquire the assets could be substantially greater than what has been estimated in the Study.

- The feasibility analysis reflects an estimate of standard future capital expenditures, but it does not reflect any incremental capital or operating costs associated with potential future storm restoration or other events that may occur.

- The Preliminary Feasibility Study relies on projections and estimates based on currently available information and reasonable assumptions as to future market conditions. However, if the City were to municipalize, additional detailed analyses would be required and the costs to be incurred by the City to acquire BHE's distribution system within the City could be materially higher.
- In addition to the relative economics of operating a municipal electric utility versus staying with BHE as the electric provider, there are a number of factors that the citizens of Pueblo should consider when making an informed decision as to whether to proceed with forming a municipal electric utility:
  - *Capability to Execute*: The citizens of Pueblo will want to make a realistic assessment of the ability of a City-owned utility to execute on its obligations to provide safe and reliable electric service at levels that approximate or exceed the level of service provided by BHE. This includes the ability to effectively manage the day-to-day operations, address and manage cyber security, outages, and emergencies, and the ability to plan for and successfully implement required future system investments.
  - *Sharing of Risk*: The risks of owning and operating an electric utility are currently shared between BHE's customers and its shareholders; however, those same risks after condemnation and the formation of a municipal electric utility would be borne entirely by Pueblo's municipal utility customers.
  - *Governance/Oversight*: The City would need to consider its ability to establish a governance structure to perform the functions that are currently provided by the Colorado Public Utility Commission ("CPUC") in order to ensure that the municipal utility continues to provide safe and reliable service in an efficient manner.
  - *Past Experience*: Nearly all of the electric cooperatives and municipal electric systems in the U.S. were formed in the early 1900s, and rarely through an acquisition approach where municipalities must acquire assets from investor-owned utilities and incur significant additional startup costs. The vast majority of communities considering forming a municipal electric utility in the past two decades have not been completed. In addition, as a result of the challenges associated with establishing new municipal electric utilities, there have also been several privatizations of municipal utilities (*i.e.*, the sale of municipal utilities to investor-owned utilities) in the past two decades.
  - *Power Acquisition Considerations*: To the extent that a municipality purchases power from a third-party provider instead of owning its own generating resources, the municipality needs to ensure that the power that it is purchasing is backed by sufficient capacity and will not be subject to such unforeseen events that may result in reliability concerns. In addition, the municipality needs to ensure that the power it is purchasing will also not be subject to unexpected and significant increases in costs during periods of

high electric utilization and/or if generating resources are not capable of producing at their full output.

- *Municipal Service Offerings and Cost Impacts*: It is important for the City to carefully evaluate the impact of each service that is currently being provided by BHE to determine whether—and on what terms—the service would be provided by the City. The rate impacts on customers in the City associated with services such as net metering (*i.e.*, the ability of a customer to provide energy back to the utility) and energy efficiency that reduce electric usage but not the costs of the electric distribution system will need to be evaluated if the City decides to municipalize.
- *Ensuring Reliability*: The electric industry is currently undergoing a transformation to modernize the electric grid to ensure reliability for customers, as well as to improve resiliency, security, flexibility, affordability and sustainability. These changes are being driven in part by the interconnection of solar generation and other distributed resources to the network and advances in information and communications technologies necessary to operate and maintain the distribution network. There are clearly costs associated with these measures, and many of these industry changes, including the implementation of information technology systems, are subject to substantial economies of scale.
- *Length of the Municipalization Process*: The municipalization process can take many years resulting in significant expenditures and cost escalation. Accordingly, the final cost to condemn the system and form a municipal electric utility may differ significantly from the cost estimated in an initial feasibility analysis.

1 INTRODUCTION

Concentric has performed a Preliminary Feasibility Study that estimates the costs and assesses the implications of the City acquiring BHE's existing electric distribution assets within the Pueblo city limits and assuming responsibility for providing electric service to BHE's electric customers within Pueblo.[7] As an independent assessment, the Preliminary Feasibility Study presents certain facts and perspectives to inform the primary stakeholder constituencies: BHE as the current electric utility owner and service provider; the City and its officials; and the residents and businesses that depend on safe, reliable and reasonably priced electric service.

Concentric has evaluated the projected future cost of providing electric service under two options:

(1) continuation of BHE as the electric service provider in Pueblo (*i.e.*, the BHE Option); and

(2) service provided by a newly formed City municipal electric utility (*i.e.*, the City Option).

The future cost of the BHE Option is a function of future rate increases that may be required associated with BHE continuing to own and operate the electric utility, including the projected cost of generation. The future cost of the City Option is a function of the costs to be incurred by the City to acquire the assets subject to the municipalization, the costs to be incurred to establish a new municipal electric utility, and the costs for the City to operate and maintain its new electric distribution system.[8]

In addition to comparing the future costs to electric customers in Pueblo under the City Option to the BHE Option, there are various risk factors that should also be considered by the City in deciding whether to assume responsibility for providing electric service. For example, the City would need to evaluate its capability to safely, reliability and efficiently own and operate a new municipal utility, including the ability to respond to outages and other unforeseen challenges. The City would also need to consider its ability to establish an appropriate oversight/governance structure, it and would need to consider future rate impacts of providing comparable service offerings.

The Preliminary Feasibility Study is composed of the following sections:

Section 2: Background on Pueblo, Colorado – provides a brief overview of the City.

Section 3: The Municipalization Process and Experience – provides a discussion of the municipalization process and an overview of the economics of forming a municipal electric utility.

Section 4: Recent Municipalization Experience – provides a discussion of municipalization experience in the U.S. since 2000, providing important context for the decision faced by the City.

Section 5: Projected Acquisition Costs for the City Option – identifies and estimates the various costs to be incurred by the City prior to Day 1 of municipal utility operations,

[7] This Preliminary Feasibility Study provides a high-level analysis of the valuation of BHE's assets within the Pueblo city limits. A more detailed review, certified appraisal report, and engineering analysis is likely to be required should the acquisition be approved by Pueblo voters.

[8] As discussed herein, these costs include the costs of the physical assets to be acquired, all stranded costs, separation and reintegration costs, transition-related costs and startup costs.

including the costs associated with condemnation, the City acquiring BHE's electric distribution system, and for the City to commence operations.

Section 6: Projected Operating Costs for the City Option – identifies and estimates the ongoing costs that would be incurred by the City to own and operate an electric distribution system within the city limits, including the debt service costs attributable to the acquisition.

Section 7: Project Future Cost of the BHE Option – presents the estimated costs to the electric customers in Pueblo of future electric service under the BHE Option.

Section 8: Preliminary Feasibility Study Financial Results – compares the projected costs under the City and BHE Options, and also provides two alternative scenarios (*i.e.*, a higher and lower cost of municipal operation of the electric utility) and a sensitivity analysis that illustrates the effect of changing key assumptions of the Preliminary Feasibility Study.

Section 9: Additional Considerations – provides a discussion of additional factors that the citizens of Pueblo should consider when deciding whether to form a municipal electric utility within the City.

2 BACKGROUND ON PUEBLO, COLORADO

2.1 DEMOGRAPHICS

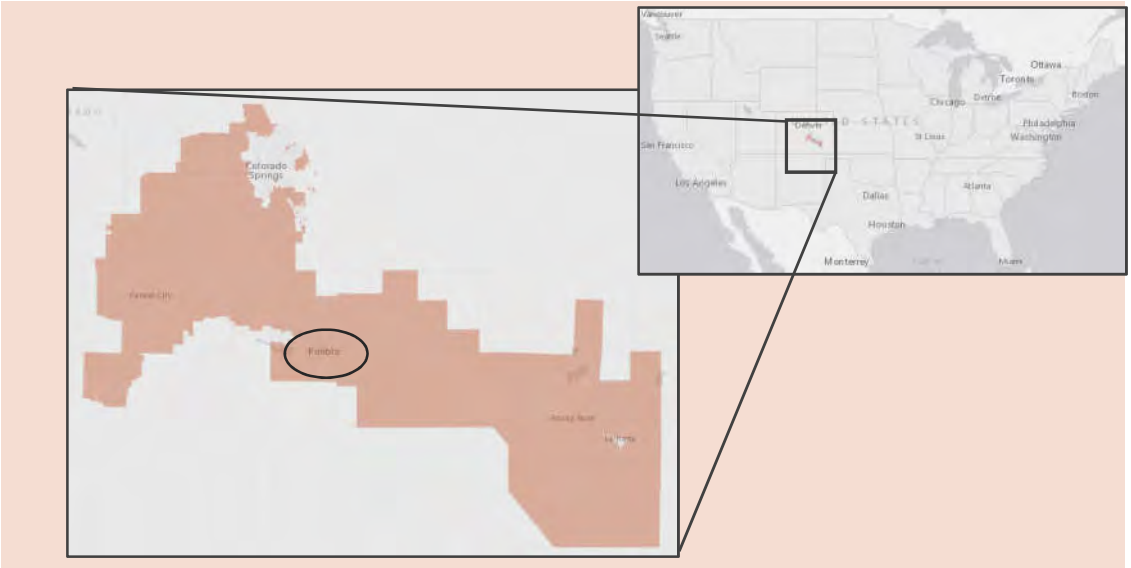
The City of Pueblo was incorporated in 1870, and is the county seat of Pueblo County, Colorado. The city is located in southeastern Colorado approximately 110 miles south of Denver. Pueblo encompasses a land area of approximately 54 square miles.

Figure 1: Demographic Summary[9]

	Colorado	Pueblo
Population (as of July 2018)	5,695,564	111,750
No. of Households	2,082,531	43,290
Median Household Income	$65,458	$36,280
Unemployment Rate (as of July 2019)	2.9%	4.4%
% Owner Occupied Housing Units	65%	55%
Median Value of Owner-Occupied Housing Units	$286,100	$121,200

2.2 MUNICIPALIZATION HISTORY

BHE purchased its Colorado utility operations from Aquila in 2008 and as of 2018 served approximately 96,700 electric customers in southeastern Colorado, approximately 57% of which are located within Pueblo.

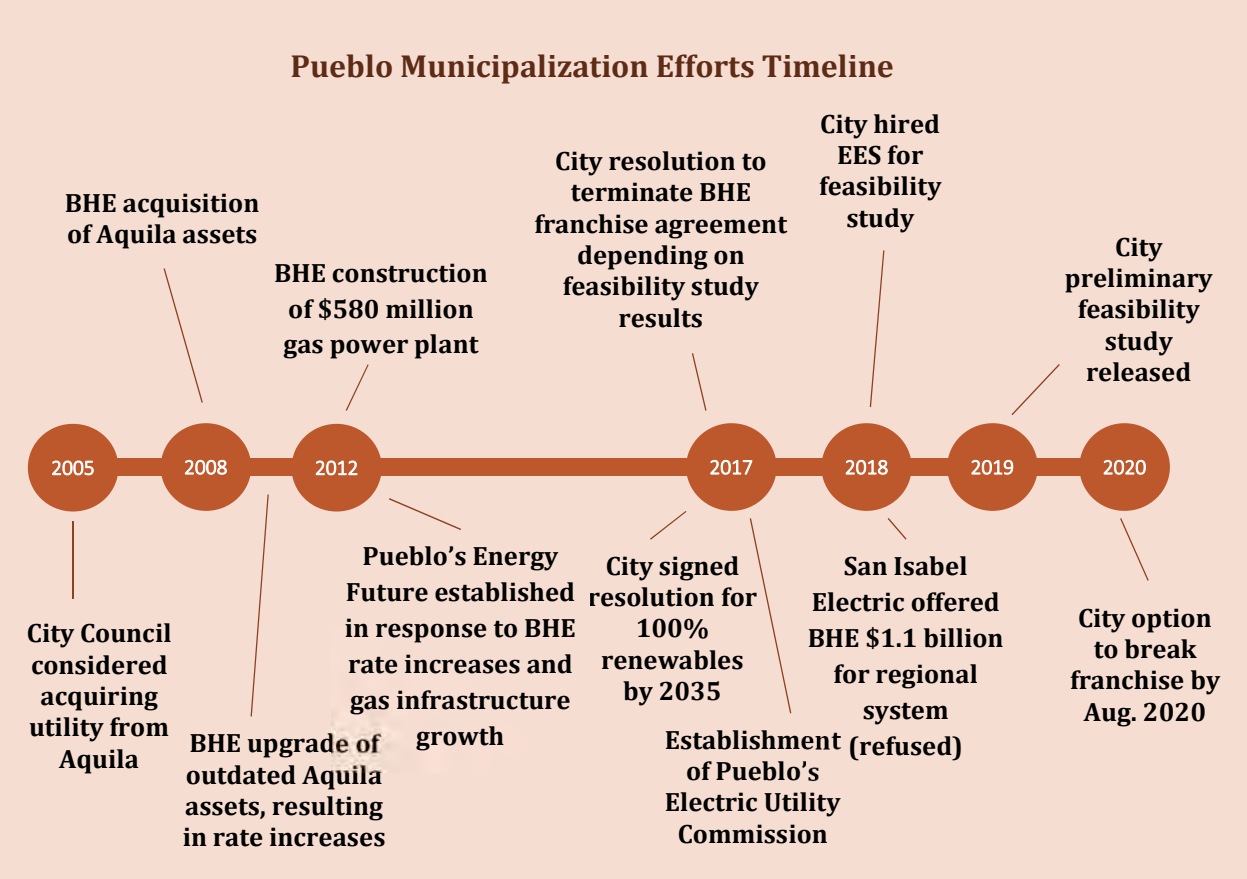


Since the acquisition from Aquila, BHE has invested heavily in the utility infrastructure, including construction of a $580 million natural gas-fired generating plant, as well as replacement of aging

[9] United States Census Bureau, QuickFacts; U.S. Department of Labor, Bureau of Labor Statistics.

infrastructure throughout the system. As a result, electric utility rates have increased, prompting critiques from customers and consumer advocacy groups. In 2017, the City Council voted to become 100% renewable by 2035 and also established Pueblo's Electric Utility Commission ("EUC").

The City is currently evaluating alternatives to the existing non-exclusive BHE franchise agreement with Pueblo. In January 2018, the EUC began meetings and approved the commissioning of a feasibility study. In July 2018, the EUC hired EES Consulting to conduct an initial feasibility study, which was released in January 2019. The timeline below highlights key events in Pueblo's municipalization efforts.



Pueblo's municipalization efforts are primarily driven by concerns over utility rate levels and their impact on low income customers and economic development for local businesses. Pueblo has a sizable low-income population, with approximately one in five residents living below the poverty line. Pueblo also has renewable goals, with grassroots organizations such as Pueblo's Energy Future and the Sierra Club spearheading efforts including the City's 2017 resolution for 100% renewables by 2035.

A key consideration for Pueblo is its desire to fund the municipalization process, and the potential that rate increases could be exacerbated by lengthy municipalization-related legal proceedings. Boulder has been pursuing municipalization for over a decade, having already spent over $20 million

through March 2019 on its municipalization efforts.[10] However, the economic demographics of the two communities are quite different.

Figure 2: Demographic Comparison – Pueblo v. Boulder[11]

	Pueblo	Boulder
Population (as of July 2018)	111,750	107,353
No. of Households	43,290	42,679
Median Household Income	$36,280	$64,183
Unemployment Rate (as of July 2019)	4.4%	4.7%
% Owner Occupied Housing Units	55%	48%
Median Value of Owner-Occupied Housing Units	$121,200	$600,400

[10] Boulder Beat. "Boulder, Xcel haggling over assets. $20M spend on muni so far." March 2, 2019.

[11] United States Census Bureau, QuickFacts; U.S. Department of Labor, Bureau of Labor Statistics.

3 THE MUNICIPALIZATION PROCESS

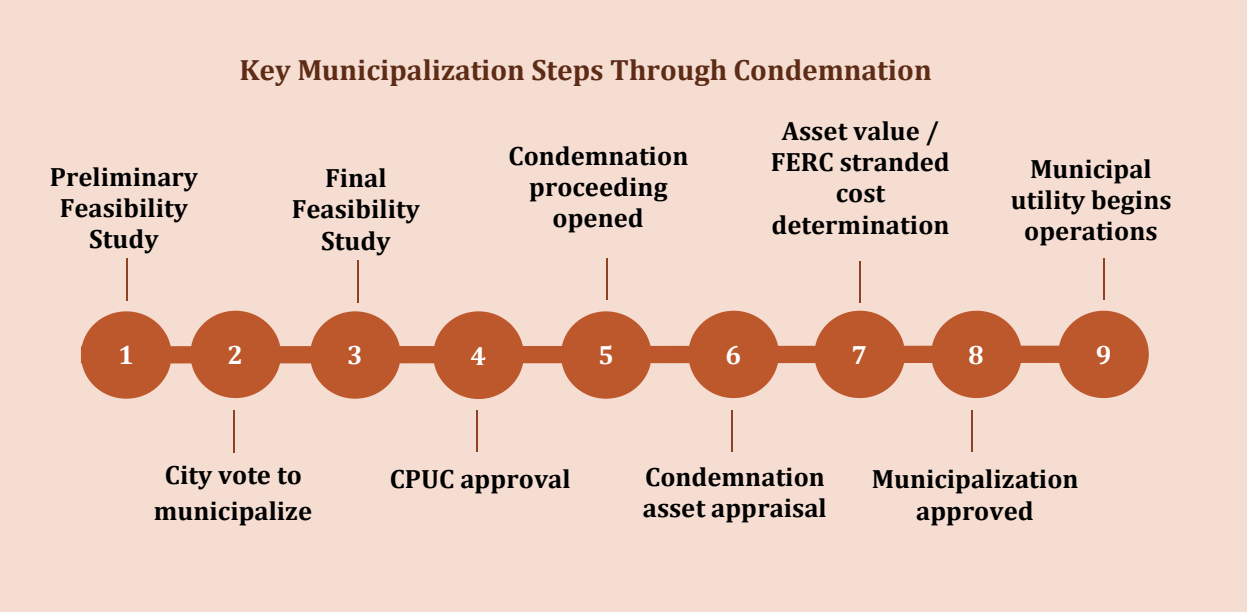
Forming a municipal electric utility can be challenging, even when it is projected that there is a compelling economic and/or public benefits case to be made. The municipality is making an irrevocable decision to finance and acquire assets from the existing utility provider, assume the obligations of providing safe, reliable, and affordable electric service, and to form an organization and governance structure to manage and operate the utility. The municipality is not only committing to acquiring existing electric assets, but to maintaining those facilities according to national standards and continuing to make investments that support the services residential and business customers expect. The Pueblo City Council and the City's voters, as the ultimate decision makers, will need to make a well-informed decision that considers economic and other considerations, recognizing that expected electricity prices may turn out to be higher or lower due to factors that are both within and beyond the municipality's control.

3.1 STEPS TO ESTABLISHING A MUNICIPAL ELECTRIC UTILITY

If the City were to municipalize, the first step required would be an affirmative vote to approve the creation of a municipal electric utility. Voters' decisions typically reflect the estimated economic impact of owning and operating a municipal electric utility based on an initial feasibility analysis. CPUC approval of the municipalization is also likely required, given that customers will remain with the investor-owned utility that will be impacted by the municipalization.

With an affirmative vote to form a municipal electric utility and any required CPUC approval, the next step would be the determination of the fair market value of the utility property to be municipalized. The fair market value would be determined either through negotiation and settlement or through a condemnation proceeding through the court system. Colorado statutes govern the condemnation process and procedures that would be required to acquire the utility's assets. Just compensation of the condemned utility property is an important factor in determining whether municipal operation of the electric utility makes economic sense. The municipality must also consider that it is often the case that this value is not known with certainty while the public is considering the option to acquire the electric utility operations. Therefore, there is risk that voters may decide to acquire the assets based on an estimated purchase price that is materially different than a final determination of value. In addition, a proceeding at the Federal Energy Regulatory Commission ("FERC") would be required to determine stranded cost amounts.

A typical sequence of activities in the municipalization process is as follows:



The municipalization process can be lengthy. First, the legal and regulatory process concerning the formation of the municipal electric utility and the determination of the value of the system can take years to complete. In addition, following court and regulatory proceedings, the community must also prepare to assume responsibility for management and operation of the utility, a process that can take a year or more to establish the necessary contracts, properly staff the new municipal utility, and conduct all of the other necessary activities required to commence municipal utility operations.

3.2 THE FEASIBILITY STUDY

A feasibility study is a report that provides the financial and operational considerations related to the formation of a municipal electric utility and the ongoing operation of that utility. As the primary source of information relied upon by municipal officials and voters, it is essential that a credible feasibility study be performed. The feasibility study should be:

- Understandable: the study should be able to be easily understood by voters interested in making an informed decision;
- Informed by Relevant Law, Policy, and Precedent: accurately consider the approvals framework that a municipality must satisfy and the future operating environment in which investment and other decisions will need to be made;
- Objective: avoid any bias in the framing of the analysis or specifying assumptions, with conclusions and recommendations informed by relevant expertise and experience;
- Comprehensive: inclusive of all relevant quantitative and qualitative considerations that can be estimated;
- Rigorous: analytically sound and consistent with professional standards;
- Consider Risks: reflect a reasonable range of potential outcomes that capture the range of uncertainty associated with both (i) "acquisition risks" (*i.e.*, the risks associated with the

initial acquisition of a municipal electric system); and (ii) "operational risks" (*i.e.*, the risk to be assumed by a municipality if it assumes responsibility for operating the utility, including the obligation to respond to severe storms and other extraordinary events); and

- Well Documented: all source materials, assumptions, and calculations should be fully documented.

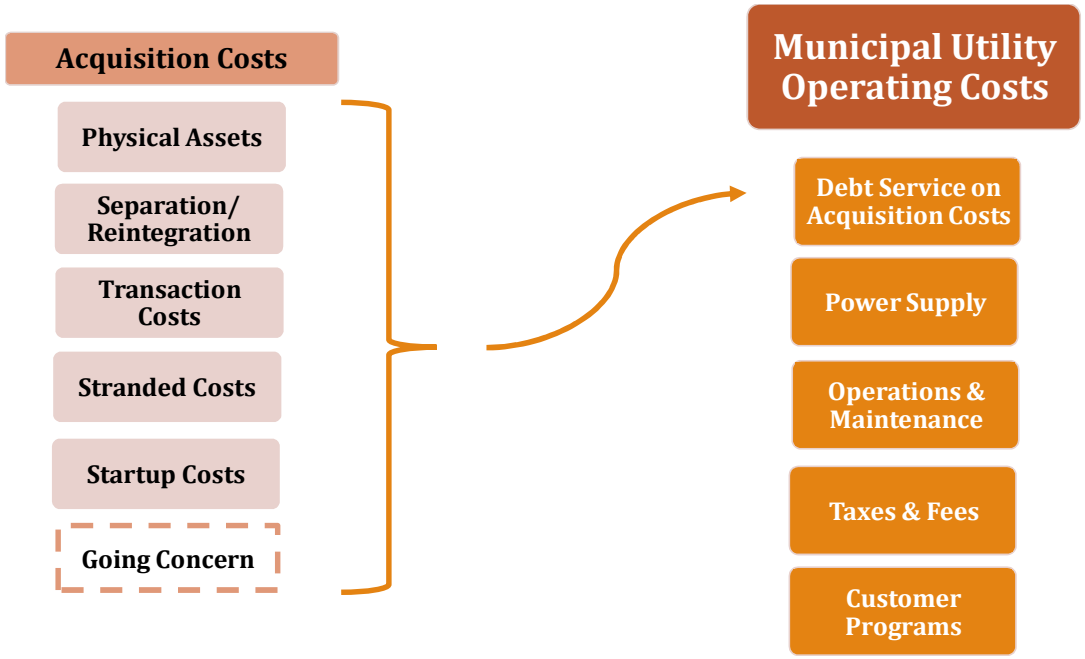
A feasibility study describes and estimates the projected future costs to electric customers in a community for service provided by a new municipal utility relative to the existing investor-owned utility. In addition, a feasibility study also discusses various other factors that a municipality should consider as it debates whether to municipalize the electric system.

3.3 OVERVIEW OF THE ECONOMICS OF MUNICIPALIZATION

Ultimately, the quantitative assessment of a feasibility study should produce a comparison of the cost and rate impact of future municipal ownership and operation versus continued ownership and operation by the incumbent utility. As noted, since there are several assumptions required to assess the economic feasibility of municipal ownership and operation of the electric system, it is also important to consider reasonable variations in those assumptions to test potential future outcomes beyond a base case or most likely scenario.

As shown in Figure 3, the cost of providing electric service to be assessed in a feasibility study includes two overarching components – the initial acquisition costs; and the ongoing operating costs of the municipal utility.

Figure 3: Overview of the Costs of Municipalization



Acquisition Costs

First, there are the costs to be incurred by the municipality to acquire the utility property, along with the costs associated with the transaction and the required start-up costs to commence operations:

- Physical Asset Costs: The costs to the municipality to acquire the physical electric utility property, including the physical transmission and/or distribution assets, land, easements and projects started but not yet in-service.
- Stranded Costs: The costs associated with the generation, transmission and distribution utility infrastructure investments that become redundant or "stranded" after the condemnation or asset sale and are no longer required as a result of the municipalization.
- Separation and Reintegration Costs: The cost of separating the municipal utility from the remaining utility system and reintegrating the incumbent utility's remaining electric system such that safe and reliable service is maintained to its remaining customers at the level prior to the municipalization.
- Startup Costs: Costs to begin operation as a municipal utility, including initial capital expenditures, equipment inventory, facilities, fleet vehicles, staffing, and information technology, as well as the cost associated with maintaining cash balances to support day-to-day operations of the utility and respond to unanticipated events, including securing outside crews and equipment to assist with emergency storm restoration.
- Transaction Costs: Costs incurred to execute the transaction to acquire the utility's assets, including underwriting and debt issuance costs, as well as legal, engineering and consulting costs.
- Going Concern: The incremental lost value to the utility attributable to the fact that the distribution assets that are the subject of a condemnation are not just a collection of physical assets, but together comprise a business unit that is complete, functional, and can be run as a business unit on day one of the acquisition. This value is derived from all the elements that contribute to the complete operating business segment. Whether the value of going concern is included as part of the overall acquisition cost, and if so, the manner in which the value is calculated, is generally determined through state statute, precedent and/or litigation proceedings.

Operating Costs

Second, once the electric system has been acquired, there are the various ongoing costs that will be incurred by the municipality as the new electric service provider for customers in the community:

- Power Supply Costs: the cost of purchasing electricity to meet the peak demand and hour-to-hour variable energy requirements of customers throughout the year, and the cost of transmitting the power purchased to the expected point of delivery to the new municipal electric utility system.
- Operation and Maintenance ("O&M") Expense: the cost to operate and maintain the transmission and/or distribution systems, including substations, distribution lines,

transformers, and communication facilities, as well as the costs attributable to vegetation management, utility crews and equipment. This includes administrative and general expenses (*e.g*., administrative salaries, wages and benefits, insurance, outside services, rents, and other expenses not attributable to a specific utility function) and customer service expenses (*e.g*., billing, collection, and customer information systems).

- Debt Service/Financing Costs: the combination of the principal and interest payments on the debt incurred to fund: (i) all of the acquisition-related costs of the utility system being acquired, including any stranded costs, separation/reintegration costs, transaction costs and startup costs; (ii) cash working capital required to operate the municipal utility; (iii) projected capital investments in the first few years of municipal operation that are required to replace utility system assets, including assets that have failed or that are beyond their service life; and (iv) a reserve fund required to ensure the ability of the municipality to meet its debt repayment obligations.
- Customer Programs: the cost of providing energy efficiency, low-income energy assistance and other programs.
- Taxes and Fees: Replacement of local property taxes, franchise and other fees formerly paid by the utility to the municipality.

The financing costs for a municipality to acquire an electric utility's distribution and/or transmission assets are based on the level of borrowing costs and the amount being financed. As described in Section 5, while municipal utilities can issue low-interest, tax-exempt debt to finance their future capital needs, the City's acquisition of the physical assets from BHE would likely be financed with taxable debt similar to the debt relied upon by BHE and other investor-owned utilities that finance investments to replace aging infrastructure, modernize the network, and support new services.[12] All financing costs are included in the total costs of providing basic electric service (commonly referred to as "revenue requirement") and recovered through electricity rates charged to customers.

3.4 ADDITIONAL CONSIDERATIONS

In addition to the economic analysis of the future cost of electric service being provided by a new municipal utility versus the existing investor-owned utility, there are a number of additional factors and risks that a community should consider before deciding to take ownership of an electric distribution system and form a new municipal utility. These considerations include the ability of the municipality to perform the necessary functions of operating and managing the utility in a safe and efficient manner, maintaining reliability under favorable weather conditions as well as the ability to respond to and fund storm-related and other extraordinary outages, the services to be offered and the impact on future rates, and other recent experience of communities considering municipalization. These additional factors are discussed in more detail in Sections 4 and 9.

[12] Public Finance Network. "Tax-Exempt Financing: A Primer", p. 22.

4 EXPERIENCE FORMING MUNICIPAL ELECTRIC UTILITIES

4.1 OVERVIEW

While there have been communities that have explored municipalization in the U.S. in the past two decades, many efforts have failed or been abandoned. Specifically, as shown in Figure 4, 64 communities since 2000 have considered or are currently considering municipalization, with just 11 having formed a municipal electric utility to date, and 2 of those communities having agreed to be subsequently sold back to the investor-owned electric utility. The vast majority of the communities have decided not to proceed with municipalization for a variety of reasons, including being rejected by voters or denied by a regulatory commission, and the costs and time necessary to complete the effort greatly exceeding original estimates.[13] In many instances, feasibility studies performed on behalf of municipalities frequently underestimate both the time and cost of completing municipalization efforts that do not have the cooperation of the existing utility service provider.

Figure 4: United States Municipalization Efforts: 2000–2019[14]

Municipality	Utility	Year	Status
Sloan, NY	New York State Gas & Electric	2000	Referendum failed
Las Cruces, NM	El Paso Electric Company (EPE)	2000	Abandoned
Lakewood, NY	Niagara Mohawk	2000	Abandoned
Lakewood, WA	Puget Sound Energy	2000	Defeated in Council
Watford City, ND	Montana Dakota Utilities	2001	Referendum failed
San Francisco, CA	Pacific Gas & Electric Company	2001	Referendum failed
Wichita, KS	Western Resources	2001	Abandoned
Hermiston, OR	Pacific Power & Light	2001	Completed
Village of Hamburg, NY	New York Gas & Electric	2001	Abandoned
Wagner, SD	Northwestern	2002	Rejected by Voters
Oakland, CA	Pacific Gas & Electric Company	2002	Abandoned
Saint Henry, OH	Dayton Power & Light, Midwest Electric	2002	Abandoned
Hercules, CA	Pacific Gas & Electric Company	2002	Completed (sold back to PG&E in 2014)
Corona, CA	Southern California Edison	2003	Abandoned by City Council
Casselberry, FL	Progress Energy Florida	2004	Abandoned
Chula Vista, CA	San Diego Gas & Electric	2004	Abandoned
Clackamas, OR	Portland General Electric Co.	2004	Abandoned
Elk City, OK	American Electric Power	2004	Completed (sold back to AEP in 2010)
Rancho Cucamonga, CA	Southern California Edison	2004	Completed
Moreno Valley, CA	Southern California Edison	2004	Completed
San Marcos, CA	San Diego Gas & Electric	2004	Abandoned
Pueblo, CO	Aquila	2005	Defeated in Council
Fairfield, IA	Alliant Energy Corp.	2005	Abandoned
Winter Park, FL	Progress Energy Florida	2005	Completed
Cerritos, CA	Southern California Edison	2005	Completed
Oregon Mutual Utility Development	Portland General Electric Co.	2005	Rejected by Governor
Maitland, FL	Progress Energy Florida	2005	Rejected by City Council
Iowa City, IA	MidAmerican Energy	2005	Rejected by Voters
Belleair, FL	Progress Energy Florida	2005	Rejected by Voters
Island Power, Pittsburg, CA	Former Military Base	2006	Completed
Yolo Country, CA	Pacific Gas & Electric Company	2006	Rejected by Voters
City of Paris, IL	Ameren Illinois	2007	Abandoned

[13] For example, in the case of Las Cruces, New Mexico, in 1991, the city's consultant projected it would cost the city between $13 million and $26 million to acquire the system. In 1999, Las Cruces abandoned its takeover effort after the estimated costs escalated to over $105 million.

[14] Data derived from various news publications and S&P Global Market Intelligence.

Municipality	Utility	Year	Status
Titonka, IA	Interstate Power & Light Co.	2007	Abandoned
City of Atka	Andreanof Electric Corp.	2008	Completed
Everly, IA	Interstate Power & Light Co.	2008	Rejected by Iowa Utilities Board
Kalona, IA	Interstate Power & Light Co.	2008	Rejected by Iowa Utilities Board
Rolfe, IA	Interstate Power & Light Co.	2008	Rejected by Iowa Utilities Board
Terril, IA	Interstate Power & Light Co.	2008	Rejected by Iowa Utilities Board
Wellman, IA	Interstate Power & Light Co.	2008	Rejected by Iowa Utilities Board
San Francisco, CA	Pacific Gas & Electric Company	2008	Rejected by Voters
Skagit County, WA	Puget Sound Energy	2008	Rejected by Voters
Whidbey Island, WA	Puget Sound Energy	2008	Rejected by Voters
Marin Energy Authority	Pacific Gas & Electric Company	2010	Abandoned (CCA instead)
City of Egegik	Egegik Light & Power Company	2012	Completed
South Daytona, FL	Florida Power & Light Co.	2012	Rejected by Voters
Thurston County, WA	Puget Sound Energy	2012	Rejected by Voters
Jefferson County, WA	Puget Sound Energy	2013	Completed
City of Klamath Falls, OR	PacifiCorp	2013	Abandoned
Santa Fe, NM	PNM Resources Inc.	2013	Considering
Minneapolis, MN	Xcel Energy Inc.	2013	Abandoned
Cape Coral, FL	LCEC	2014	Abandoned
Island of Maui, HI	Hawaiian Electric Industries	2015	Considering
Millersburg, Oregon	PacifiCorp	2015	Rejected by Voters
DC Public Power	Pepco	2015	Abandoned
California Electrical Utility District	PG&E, SDG&E SCE	2015	Abandoned
City of Klamath Falls, OR	PacifiCorp	2016	Considering
Bainbridge Island, WA	Puget Sound Energy	2017	Abandoned
City of Destin, FL	Gulf Power	2017	Considering
Boulder, CO	Xcel Energy Inc.	2017	Approved
Pueblo, CO	BHE	2018	Considering
Decorah, IA	Interstate Power & Light	2018	Considering
Davis, California	Pacific Gas & Electric Company	2018	Abandoned (CCA instead)
San Francisco, CA	Pacific Gas & Electric Company	2019	Considering
State of Maine	Emera and AVANGRID	2019	Initial study requested

4.2 CASE STUDIES

The majority of the large public power agencies in the U.S. were established over a half of a century ago in the 1930s and 1940s, and therefore have embedded cost structures that differ from a newly formed municipal utility. Consequently, the most recent cases are most instructive as to the challenges of forming a municipal electric utility. In several of these cases, the acquisition of the electric utility assets of the investor owned utility at costs that greatly exceeded original estimates. While there are a number of successful examples of transitions to municipal operation of the electric utility, the case studies below highlight potential issues that cities should be aware of in considering municipalization. Whereas investor-owned utilities see risks shared between customers and company shareholders, municipal utility customers shoulder ongoing operational risks entirely.

As noted, acquisition costs and operating costs are often understated, diminishing meaningful savings opportunities and resulting in higher than projected municipal electricity rates. While there are circumstances where a municipal acquisition of the existing electric utility can have positive outcomes for customers, there are several recent cases in which the municipality assumed significant risks and its customers faced higher costs as a result of assuming control and operation of the utility.

WINTER PARK, FLORIDA

Costs escalated from an original estimate of $16 million to nearly $50 million by the time the takeover of the local electric system was completed.

Winter Park formed an electric utility in 2005 by acquiring the local electric distribution assets of Progress Energy, exercising a right-to-purchase clause that is unique to Florida franchise conditions. Despite agreeing to compensation being determined through arbitration rather than litigation, the effort took six years. When initially setting municipal electric rates, Winter Park held the electric rates at the same level as Progress Energy. While representing in its bond issuance an expectation to make millions of dollars a year, instead Winter Park ended up losing approximately $11 million over the first four years of municipal operation and was placed on credit-watch negative by rating agencies.[15] In 2008, Winter Park experienced decreased electric sales and an increase in the cost of bulk power, causing net revenue to decrease below the minimum 1.25 times debt service ratio to 0.73.[16]

JEFFERSON COUNTY, WASHINGTON

Jefferson County Public Utility District No. 1 ("JPUD") contracted a feasibility study for the purchase of the electric distribution assets owned by Puget Sound Energy ("PSE"), valuing them at approximately $47 million,[17] which was less than half of the final acquisition cost of over $100 million, excluding start-up expenses.

In 2008, driven by the desire to obtain local control over its electric service, JPUD initiated a municipalization process to acquire the electric distribution assets of PSE. As part of the process, JPUD contracted for a preliminary feasibility study of an electric system acquisition, which provided a 10-year comparison of the projected cost of continued electric service with PSE relative and the projected cost of service for a PUD. The study estimated that JPUD would be able to acquire PSE's assets for $47.2 million, with total financing requirements of $66 million including initial acquisition costs, separation, start-up and legal costs, working capital and financing expenses. The study concluded that JPUD could provide service beginning in 2011 at rates that were slightly higher than PSE's rates for the first three years of operation, but that rates would decrease noticeably in the fourth year, when low-cost power from Bonneville Power Authority ("BPA") became available.[18]

JPUD acquired the local electric distribution assets and service area of PSE in 2013, approximately five years after the acquisition was originally approved by the electorate. The actual acquisition and

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15 City of Winter Park, Florida Bond Issuance Prospectus, Electric Revenue Bonds, Series 2005A and Series 2005B, Initial Auction Date June 6, 2005, C-30.

16 City of Winter Park, Florida Comprehensive Annual Financial Report, at 25.

31 Preliminary Feasibility Study (D. Hittle & Associates, Inc.), Public Utility District No. 1 of Jefferson County Electric System Acquisition, October 24, 2008, at 21.

18 *Id*., at 5.

transaction costs incurred by JPUD were substantially higher than projected in the feasibility study.[19] Through a negotiated sale agreement with PSE, JPUD purchased the assets at a sale price of $109.3 million, or approximately 2.3 times the $47.2 million projection provided in the feasibility study.[20] In addition, actual operating costs and resulting electricity rates under JPUD operation have been higher than projected and now exceed PSE's rates, altering the rate comparison with PSE originally estimated in JPUD's feasibility analysis, even though many advocates of municipalization had promised no rate increase and better customer treatment.[21] JPUD has also experienced difficulties in customer service, accounting and low-income assistance programs.[22]

BOULDER, COLORADO

Boulder's municipalization efforts started approximately a decade and a half ago and remain unresolved. Boulder has an expected municipal utility start date of 2024, though buyout costs remain uncertain.

Boulder's costs associated with acquiring the distribution system within the city from Xcel Energy Inc. ("Xcel") have escalated considerably throughout the process, rising from less than $140 million in a 2005 preliminary feasibility study to between $300 and $337 million by current estimates depending on the range of separation costs. However, the current estimates do not include costs for stranded investments, originally estimated at $26 million (in 2018 dollars). While Boulder and Xcel remain far from determining acquisition costs for the system, Xcel and Boulder staffers estimate buyout costs could reach $900 million.[23]

Given the lengthy ongoing court battles, estimates for legal costs have risen dramatically over the past several years. Whereas Boulder's 2005 preliminary feasibility study did not list a figure for legal costs, Boulder's 2011 final feasibility study included $3 million in legal fees. However, as of March 2019, Boulder has spent over $20 million on its municipalization effort, and Boulder's voters approved a total of $35 million by 2022.[24]

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[19] JPUD did not rely on D. Hittle & Associates, Inc. for purposes of its negotiations with PSE. Rather, JPUD retained Brown & Kysar, Inc. to do a subsequent analysis. Brown & Kysar's predicted acquisition cost varied depending upon stated assumptions but ranged from $58 million to $83 million. WUTC Docket No. UE-132027 (prefiled direct testimony of Karl R. Karzmar).

[20] WUTC Docket No. UE-132027, Order 04, September 11, 2014, at 1.

[21] JPUD implemented two rate increases (January and June) in 2017 totaling 6.6% and another increase in 2018 of 4.8%.

[22] Myers, Todd. "Policy Brief: The failed promises and politics of Jefferson Public Power: How creation of a public electric utility led to higher rates and lower customer service." Washington Policy Center, December 2016, at 6-7.

[23] https://bldrfly.com/features/boulders-municipalization-effort-explained/; https://www.bizjournals.com/denver/news/2017/04/18/boulder-council-votes-to-move-forward-on-city.html

[24] Boulder Beat, "Boulder, Xcel haggling over assets; $20M spend on muni so far", March 2, 2019; Jaffe, Mark. "Boulder wanted its own electric utility. Does it still?" The Denver Post. October 27, 2017. Available at: https://www.denverpost.com/2017/10/27/boulder-wanted-its-own-electric-utility-does-it-still/.

4.3 RECENT PRIVATIZATIONS AND INVESTOR-OWNED UTILITY MANAGEMENT

As a result of the challenges associated with operating municipal electric utilities, there have also been several privatizations of municipal utilities (*i.e.*, the sale of municipal utilities to investor-owned utilities) since 2000. Figure 5 summarizes the municipal electric utilities that have recently been sold to investor-owned utilities.

Figure 5: Recent Electric Privatization Activity

Utility	Municipality	Municipalization Year	Privatization Year
American Electric Power Company	Elk City, OK	2004	2010
Central Vermont Public Service	Readsboro, VT	Pre-2000	2011
Indiana Michigan Power Company	City of Fort Wayne, IN	Pre-2000	2011
Pacific Gas & Electric Company	Hercules, CA	2002	2014
Rocky Mountain Power	Eagle Mountain City, UT	Pre-2000	2015
Florida Power & Light Co.	Vero Beach, FL	Pre-2000	2018

In addition to the cases summarized in Figure 5, Jacksonville Electric Authority, the municipal utility in Jacksonville, Florida is currently exploring privatizing its system. Also, although not privatized through a sale to an investor-owned utility, the Long Island Power Authority ("LIPA") has been forced to select an investor-owned utility to manage its assets after significant cost escalation and mismanagement.

Further details regarding recent examples of the privatization activity are described below.

VERO BEACH, FLORIDA

In 2009, a complaint filed against Vero Beach expressed concerns over the municipal utility's electric rates, use of electric utility funds, and customer representation. At that time, driven by poor management decisions, the municipal utility's residential rates were approximately 20-30% higher than comparable electric rates of Florida Power & Light, a neighboring investor-owned utility.[25] The sustained higher rates and resulting customer complaints prompted the city to pursue privatization, which was ultimately completed in 2018, almost a decade after starting the process. After the lengthy process, Vero Beach completed the privatization of its municipal electric utility by selling it to Florida Power & Light.

[25] Florida Public Service Commission. "Comparative Rate Statistics." December 31, 2009. http://www.psc.state.fl.us/Files/PDF/Publications/Reports/General/Comparative/December%2031,%202009.pdf; FL PSC Docket No. 20090524. Complaint of Stephen J. Faherty and Glenn Fraser Heran against the City of Vero Beach for unfair electric utility rates and charges, December 3, 2009, at 2-4.

FORT WAYNE, INDIANA

Since the 1970s, Indiana Michigan Power Company ("IMPC") had leased the electric distribution assets in the City of Fort Wayne, Indiana. In 2010, the parties were considering renewal of the lease or full ownership by either the city or IMPC. After months of negotiations, the city and IMPC signed an agreement for the IOU to take control of the electric system, citing an end to expensive litigation as a key benefit of the agreement. IMPC agreed to pay the city $5 million upfront and $34.2 million spread over multiple years, and the transfer was completed in 2011. A significant driver for the sale was that the city would gain access to the City Light Trust Fund, established over 35 years earlier with an approximate value of $36 million, as well as an overfunded pension obligation of $700,000. In addition, IMPC paid $39 million over 15 years to the city for its electric distribution assets. This privatization highlights the often conflicting priorities faced by cities with municipal utilities, as in this circumstance, the city determined funds were best spent elsewhere than on continuing service through its municipal electric utility.[26]

LONG ISLAND POWER AUTHORITY, NEW YORK

LIPA was originally created under the Long Island Power Act in 1985 as a state subdivision. Cost and reliability concerns grew over time, punctuated by Superstorm Sandy, after which Long Island customers saw significant delays in power restoration. LIPA's debt costs became an onerous issue and were restructured multiple times as a result. LIPA had a debt ratio double that for comparable large public power utilities,[27] and was projecting $8 billion in debt by 2018.[28] Between 2006 and 2012, storm costs (excluding Superstorm Sandy costs) exceeded annual budgets by an average of 239%.

In 2013, the state enacted legislation to stabilize rates, improve service, and improve accountability at LIPA. A 2015 report filed by the New York State Comptroller found that LIPA's average residential retail rate was 22% higher than the New York median, and 78% above the national median in 2013.[29] LIPA's commercial retail prices were worse, at 92% above the national median.[30] As a result of escalating costs and reliability issues, in 2014, LIPA was forced to select an investor-owned utility to manage its assets, choosing Public Service Enterprise Group.

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26 S&P Global Market Intelligence, "AEP to own system, serve full Fort Wayne, Ind., territory under settlement with city" October 29, 2010; City of Fort Wayne. "Light Lease Settlement." December 8, 2010. Available at: https://www.cityoffortwayne.org/144-mayors-office/321-light-lease-settlement.html; City of Fort Wayne, IN. "City Light Lease Settlement Announcement." Available at: https://www.cityoffortwayne.org/images/stories/mayors_office/docs/aep_major_term.pdf.

27 https://www.osc.state.ny.us/press/releases/july15/072415.htm

28 https://www.osc.state.ny.us/reports/pubauth/lipa_by_the_numbers_7_2015.pdf

29 https://www.osc.state.ny.us/press/releases/july15/072415.htm

30 https://www.osc.state.ny.us/reports/pubauth/lipa_by_the_numbers_7_2015.pdf

JACKSONVILLE , FLORIDA

Jacksonville Electric Authority ("JEA") is the current municipal electric utility for the City of Jacksonville, Florida, but is currently undertaking efforts to privatize its system. The move stems from low sales driven by efficiency gains and distributed generation, which has led to rate increases, with more expected in the future. In November 2017, a member of the JEA Board of Directors originally suggested JEA consider privatization, but progress on the matter paused for most of 2018 while the utility dealt with executive turnover. In May 2019, JEA staff warned the Board of Directors of lower sales and noted that pursuing privatization would be the best way to avoid layoffs and rate increases. According to the presentation, JEA could face a $2.3 billion cash gap in 2030. In order to address this gap, JEA would need to increase rates by 52%, or increase rates by 40% and stop contributions to the city. The utility would likely also need to lay off a significant portion of its staff. This cash gap was caused in part by increasing operating expenses and decreasing revenues.[31]

JEA underestimated the impact of energy efficiency and other trends on its business. Specifically, between 2007 and 2017, energy efficiency accounted for more than a 90% reduction in sales, causing JEA a loss of $1.4 billion in free cash flow. Additionally, JEA's contributions to the city would have been $80 million per year higher under original forecasts. Distributed generation is also poised to continue impacting the utility, with JEA losing more than $2.5 million in annual net income to distributed generation, and further disruption is expected as customer-owned distributed generation plus storage is projected to be at cost parity with JEA by 2025. JEA has increased rates 71% since 2006 and has eliminated 407 jobs in response to these trends.[32]

A formal process to solicit interest in the privatization of JEA was launched on August 5, 2019. JEA is looking for potential buyers to demonstrate how they will embrace industry changes, add new revenue streams, and "future-proof" the business. Proposals are due by September 30, 2019, with negotiations slated to start mid-October 2019.[33]

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[31] *See, e.g.*, Bermel, Colby. "Jacksonville, Fla., utility board tables privatization activities." S&P Global Market Intelligence. May 15, 2018; Mendenhall, Mike. "JEA will look at ways to privatize the city-owned utility." Jax Daily Record. July 23, 2019. Available at: https://www.jaxdailyrecord.com/article/jea-will-look-at-ways-to-privatize-the-city-owned-utility; JEA. Meyers, Ellen. "Fla. utility JEA to explore privatization again, other ownership options." S&P Global Market Intelligence. July 23, 2019. "Board Meeting Agenda and Package. Establishing a Baseline: "Status Quo."" May 28, 2019, at 25. Available at: https://www.jea.com/Events/Board_Meetings/2019_05_28_Board_Meeting_Package/; JEA. "Florida's Largest Municipally-Owned Utility Formally Launches Competitive and Open Solicitation Process to Transform Northeast Florida." August 2, 2019. Available at: https://www.jea.com/About/Media_Relations/2019_08_02_Invitation_to_Negotiate_ITN_127-19_for_Strategic_Alternatives/.

[32] JEA. "Board Meeting Agenda and Package. Establishing a Baseline: "Status Quo."" May 28, 2019, at 17-22. Available at: https://www.jea.com/Events/Board_Meetings/2019_05_28_Board_Meeting_Package/

[33] Meyers, Ellen and Cotting, Ashleigh. "JEA solicitation seeks strategies to 'future-proof' Fla. Utility." S&P Global Market Intelligence, August 13, 2019.

5 PROJECTED ACQUISITION COSTS FOR THE CITY OPTION

As noted previously, under the City Option, the City would incur at least five separate categories of costs to acquire and establish a municipally-owned electric utility: (i) the cost of the physical assets to be acquired; (ii) stranded costs; (iii) separation and reintegration costs; (iv) transactions costs; and (v) startup costs. For purposes of the Preliminary Feasibility Study, there is no value assigned to the going concern; however, such a value could be applicable in the future if the City were to pursue municipalization.

5.1 VALUATION OF THE PHYSICAL DISTRIBUTION ASSETS

In municipalizations of electric utility property, distribution assets are typically valued by employing a cost-based valuation methodology.[34] Two commonly used cost valuation methodologies are Replacement Cost and Reproduction Cost. The Replacement Cost methodology estimates the cost to replace the system with contemporary materials, standards, design and technology, then deducts depreciation to reflect the current condition of the existing assets. In contrast, the Reproduction Cost methodology estimates the cost to reconstruct an exact duplicate or replica of the assets to be acquired, taking into consideration the current condition of the assets. In those cases where assets providing the same function would be built today in the same way as the assets being acquired, the Reproduction Cost method and Replacement Cost method would yield the same result.

The Reproduction Cost methodology often has been relied on for determining the value of the assets in an acquisition by a municipality of utility property. Specifically, the Reproduction Cost methodology develops the Reproduction Cost New ("RCN") of the assets by trending the original cost of the assets to current value using an industry-specific index, with the value of the assets then determined by deducting the estimated depreciation of the assets from the RCN to establish the Reproduction Cost New Less Depreciation ("RCNLD") value.

For the Preliminary Feasibility Study, an estimate of the value of the physical distribution assets in the City is based on the RCNLD methodology, which has been considered in other jurisdictions. The RCN estimate is developed based on a preliminary identification by BHE of distribution assets in its electric system that are required to serve customers in Pueblo as of year-end 2017, as well as asset investments currently underway that are expected to be in service by the end of 2020 and would also serve Pueblo, including substation capital projects within the city limits.[35]

The original costs of the identified assets are trended to current costs as of 2018 using adjustment factors from the Handy-Whitman Index of Public Utility Construction Costs ("Handy-Whitman

[34] This Preliminary Feasibility Study reflects estimated costs based on a set of reasonable assumptions considering the information currently available and within the scope of this analysis. The Preliminary Feasibility Study is not a formal opinion of fair market value or just compensation.

[35] An identification of the electric distribution assets within the city limits of Pueblo reflected herein is made on a preliminary basis only and the ultimate assets that may otherwise be subject to a municipalization by the City would require a more detailed study by BHE that is beyond the scope of this Preliminary Feasibility Study.

Index").[36] The Handy-Whitman Index is a generally accepted industry standard cost index used for conducting reproduction cost studies.[37] The Handy-Whitman Index has tracked utility labor, materials and equipment costs over time and includes specific indices for various types of utility assets that reflect the percentage change in the cost of goods in most utility plant accounts for every year from 1912 to the present, with 1973 as the base year (*i.e.*, 1973 = 100 for all asset types). Using the Handy-Whitman Index, an adjustment factor is calculated by dividing the index for the most recent period by the index for the vintage of the property in question. The Handy-Whitman Index reports separate indices for many regions of the United States to reflect regional cost differences and trends, and for this feasibility analysis, the Handy-Whitman Index for the region of the United States that includes Colorado is utilized.

The development of the RCN value on a preliminary basis herein reflects the value of the following asset categories:

- Land and land rights
- Structures and improvements
- Substation equipment
- Poles and fixtures
- Overhead conductors and devices
- Underground conduits and devices
- Line transformers
- Services equipment
- Meters, including smart meters
- Office and computer equipment
- Vehicles
- Stores equipment
- Tools, shop, and garage equipment
- Laboratory equipment
- Off-road power equipment
- Communications equipment
- Miscellaneous equipment
- Street lighting and signal systems

As noted, it is also necessary to depreciate the RCN value to reflect the age and condition of the assets. Depreciation is estimated by applying survivor curves based on the age and expected useful lives of the assets as determined in BHE's most recent depreciation study.

In order to estimate the value of the assets potentially to be acquired as they are expected to exist at the time of municipal ownership, the RCNLD values as of 2018 are then escalated at inflation to 2024. This reflects several years to complete the acquisition process and transition operation to the City such that the municipality could provide safe and reliable service.

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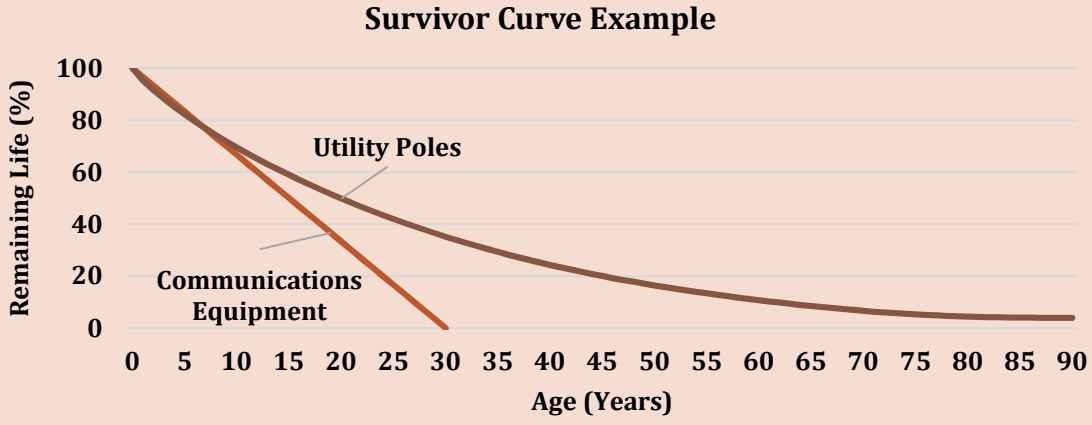
36 The Handy-Whitman Index is used to trend most cost categories; however, the Bureau of Labor Statistics producer price index is used to trend the original cost of general equipment.

37 The Handy-Whitman Index is considered an accurate and reliable resource for valuation experts, has a long history of providing dependable data, and has been published continuously since 1924 by Whitman, Requardt and Associates, an engineering firm. The Handy-Whitman Index has been used to reflect price inflation by escalating construction costs from the investment year to current dollars. The Handy-Whitman Index has been used and is generally accepted for rate-setting purposes as well as for many other purposes. For example, it has been used to value utility property for sale purposes, to perform stock valuations, and to make ad valorem tax calculations. In addition, the Handy-Whitman Index has been used for insurance purposes and for engineering estimates of new construction project costs.

Steps for Value of the Physical Electric Distribution Assets

- *Trend Original Cost Data*: Determine the RCN based on the original installed cost of each FERC account trended to current cost using cost indices (*i.e.*, the Handy-Whitman Index for most costs; and the Bureau of Labor Statistics producer price index data for general equipment, such as computers and office equipment).
- *Estimate Depreciation*: Determine the depreciation of the assets using the age and expected useful life of the asset inventory by FERC account. The age and expected useful life relied on are as determined in BHE's 2011 depreciation study. The rate of depreciation (*i.e.*, survivor curve) or expected life, vary considerably by account, which affects the level of depreciation in each account (see chart).



- *Calculate RCNLD*: Apply depreciation determined in Step 2 to the RCN determined in Step 1 to calculate the RCNLD value for each FERC account.

Based on the analysis described, Figure 6 summarizes the RCNLD value of the distribution assets within the City in 2024.

Figure 6: Estimated Cost for the City to Acquire the Physical Electric Distribution Assets in Pueblo from BHE (*in $millions, 2024*)

Description	Original Cost	RCN	Depreciation	RCNLD
Transmission Plant	$1.5	$1.7	$0.1	$1.6
Distribution Plant	$138.3	$210.0	$36.8	$173.1
General Plant	$19.5	$21.5	$7.8	$13.7
Total	**$159.3**	**$233.2**	**$44.7**	**$188.5**

5.2 STRANDED COSTS

Stranded costs in the context of municipalization are the costs incurred by the existing utility associated with the assets that become redundant or no longer necessary on the electric system as a result of the municipalization. It is estimated that the City would incur two types of stranded costs if it were to municipalize: (i) stranded substation costs; and (ii) stranded generation costs.

Stranded Substation Costs

BHE has preliminarily identified that there would be substations located within the city limits of Pueblo that feed customers outside the city limits, as well as substations located outside the city limits that feed customers inside the city limits, neither of which would be required under municipal ownership. Specifically, six substations located within the city limits of Pueblo that feed outside the city limits (*i.e.*, Fountain Lake; Northridge; Baculite Mesa; Hyde Park; Greenhorn; Airport Memorial), and four substations located outside the city limits that feed inside the city limits (*i.e.*, Airport Industrial; Stonemoor; Blende; Burntmill), are estimated to be stranded if the City were to municipalize. For purposes of the feasibility analysis, the net book value of these substations is used as an estimate of the stranded costs associated with these assets; however, a detailed engineering study would be required to determine an actual stranded substation value if the City were to proceed with municipalization. Figure 7 presents the estimated net book value for the stranded substations as of 2024.

Figure 7: The City's Estimated Stranded Substation Costs (*in $millions, 2024*)

Description	Net Book Value
Transmission Plant	$18.0
Distribution Plant	$9.3
General Plant	$0.0
Total	**$27.2**

Stranded Generation Costs

If the City were to form a municipal electric utility and serve the electric load with power supplied from generating resources other than those owned/contracted by BHE, this would cause BHE to have generation in its portfolio that was otherwise used to serve the City that would no longer be needed to serve BHE's remaining customers (*i.e.*, stranded generation). BHE could attempt to recover the cost of the generation by selling into the market. To the extent that the cost of the stranded generation is above the then-existing market price for power, there would be stranded costs associated with the generation that would need to be recovered from the City as part of a municipalization. For purposes of this analysis, it is assumed that the City would receive its power from a provider other than BHE, and thus be responsible for any stranded generation costs.

To serve its Colorado electric customers, including those in Pueblo, BHE sources its power from a combination of generation facilities that it owns and PPAs with owners of other generation assets. BHE currently has a PPA for 200 MW of energy and capacity from the Pueblo Airport Generation Station ("PAGS") that expires effective December 31, 2031. Upon the expiration of the PAGS PPA, BHE would no longer have owned/contracted generation in excess of its remaining load if the City

were to own and operate the electric utility assets in Pueblo. Accordingly, it is assumed that the stranded cost obligation that would be paid by Pueblo if it were to municipalize would be from the time of a transaction in which the City acquired BHE's distribution system in Pueblo through 2031, which is the expiration date of the PAGS agreement.

The FERC's Order No. 888[38] specifies the calculation of stranded generation costs as follows:

(Power Supply Revenues – Market Price of Power) x Load Loss

Using this formula, stranded generation costs are calculated by comparing BHE's average projected cost of generation (expressed on a $/MWh basis) to the projected market price of power (also expressed on a $/MWh basis), with the difference in each year then multiplied by the amount of projected electric usage in Pueblo. The initial assumption in the Preliminary Feasibility Study for BHE's average projected cost of generation begins with BHE's existing cost of generation based on data reported in BHE's FERC Form No. 1, and includes all costs associated with the utility's generation portfolio in Colorado (*i.e.*, fuel costs, O&M expenses, depreciation, return and income taxes). BHE's projected generation costs are then escalated to each year through 2031 and are divided by the total power required to serve its Colorado customers in each year to produce an average annual generation cost per megawatt-hour ("MWh"). BHE's average annual cost of generation per MWh is then compared to the market price of power in the region for each year through 2031 as reflected in the most recent independent electric price forecast for the Colorado-East region produced by ABB EPM Advisors ("ABB"). ABB, a leader in power market forecasting, conducts ongoing research and analysis of the electricity and fuel markets in North America and publishes semi-annual reference case forecasts in the spring and fall of each year for several market regions across the United States. The reference case forecast provides hourly, monthly average and annual average projected energy prices, which are the result of ABB's detailed modeling of the electricity markets.[39]

The difference between BHE's cost of power and the market price of power in each year is then multiplied by the annual load in Pueblo to determine the expected generation revenue shortfall, if any. Figure 8 compares the estimated BHE generation costs to the ABB market price forecast from the assumed start date of the municipal utility through 2031.

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[38] Federal Energy Regulatory Commission website; available at: https://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp. Note, in a 2013 decision, FERC denied without prejudice the City of Boulder's assertion that the city will have no stranded cost obligation from its former retail supplier, Public Service Company of Colorado, if the city municipalizes. (144 FERC ¶ 61,069 (2013)).

[39] ABB's reference case forecast of electric markets reflects existing installed generating capacity and transmission infrastructure, as well as projected infrastructure additions and retirements, over the forecast period. In addition, ABB's reference case forecast considers macroeconomic conditions that affect the supply and demand balances within and between regional markets, underlying fuel costs, transmission constraints and other market conditions that would affect the market clearing price for various electricity products, underlying fuels and emissions.

Figure 8: Estimated BHE Stranded Generation Costs

	2024	2025	2026	2027	2028	2029	2030	2031
Projected BHE Generation Cost ($/MWh)	$76.13	$77.15	$78.76	$83.51	$84.79	$86.05	$87.67	$88.93
Market Price - Energy + Capacity ($/MWh)	$58.65	$60.54	$64.51	$67.00	$69.38	$71.60	$74.97	$77.01
Revenue Shortfall ($/MWh)	$17.48	$16.61	$14.25	$16.51	$15.41	$14.45	$12.71	$11.92
Pueblo Load (MWh)	887,698	894,977	902,316	909,715	917,175	924,696	932,278	939,923
Revenue Shortfall ($millions)	**$15.5**	**$14.9**	**$12.9**	**$15.0**	**$14.1**	**$13.4**	**$11.8**	**$11.2**
Net Present Value ($millions)	**$79.9**							

If the City were to municipalize, the manner in which stranded generation costs were to be recovered would also have to be resolved. For example, one approach to recovering the stranded generation costs would be to determine the stranded cost obligation at the time of City's acquisition of BHE's distribution assets in Pueblo based on the then-current projections of forward electric prices, with the City compensating BHE for those future stranded generation costs as part of the overall acquisition price. In the alternative, the actual stranded costs could be determined on a year-by-year basis after an acquisition by the City of BHE's distribution assets in Pueblo. In this approach, the City would compensate BHE on a periodic basis through 2031 for all stranded generation costs rather than establishing a value at the time of an acquisition.

For purposes of this feasibility analysis, the stranded costs are estimated based on a comparison of BHE's future generation costs relative to the projected price of power, and the total net present value of the City's stranded cost obligation is reflected as part of the overall acquisition costs.[40] The discount rate for determining the net present value of the stranded costs as acquisition date reflects BHE's pre-tax weighted average cost of capital based on the capital structure and costs of debt and equity as authorized in BHE's last rate proceeding.

5.3 SEPARATION AND REINTEGRATION COSTS

Separation costs are the costs that would be incurred by BHE to sever service between the City and the rest of the BHE system to create a stand-alone electric utility serving the City. Separation costs would include equipment such as new substations and other equipment required by the City or BHE to continue service. Similarly, reintegration costs are those costs that would be necessary to reconnect BHE's transmission and distribution network so that it provides comparable service to its remaining utility customers following a municipalization by the City. Reintegration costs would include costs such as constructing new distribution lines to reconnect existing customers.

To develop detailed estimates of separation and reintegration costs, it is necessary to conduct detailed engineering studies to determine how to sever and reconnect the existing BHE system and to create a contiguous municipal electric utility system. At this time, these studies have not been conducted and therefore the estimated separation and reintegration costs for the Preliminary Feasibility Study reflect the range of costs estimated during other municipalization efforts. Given

[40] If the stranded generation costs were not included as part of the acquisition costs and instead were expensed through 2031, the acquisition costs for the City Option would be relatively lower, but the ongoing operating costs of the municipal utility (as discussed in Section 5) would be higher.

the uncertainty associated with potential future separation and reintegration costs, a conservative approach is taken whereby the estimated separation and reintegration costs reflect 15% of the acquisition cost of the physical electric distribution assets in Pueblo. However, it is important to note that the extent of separation and reintegration that may be required should the City municipalize reflects the specific circumstances of the existing BHE system and that each system is different. If the City were to municipalize, it would be required to fund a detailed engineering study to determine the actual separation and reintegration costs.

Considering that the City is interconnected to a large degree with the rest of BHE's Colorado electric system, the separation and reintegration costs to sever the two systems, construct the additional infrastructure needed, and reconnect existing BHE customers outside the city limits may be higher than the costs incurred by other municipalities that are not as integrated into the utility's distribution system. Furthermore, if Pueblo were to municipalize, there may be costs associated with additional transmission that BHE may require to adequately serve its remaining distribution customers once the PAGS PPA expires that would be unnecessary absent municipalization.

5.4 TRANSACTION COSTS

The City would incur legal and other professional services costs (*e.g.*, consulting; engineering) and financing costs to pursue condemnation and close the transaction. As noted, the legal process for establishing the acquisition price of the distribution system can be a lengthy process involving various courts, the FERC and the CPUC, particularly if the outcome is determined through condemnation rather than negotiation. Financing or underwriting fees (known as flotation costs) are estimated to be 1.5% of the total borrowed amount, which represents the physical assets financed with taxable debt and the remaining acquisition costs (*i.e.*, the transaction costs discussed in this section and the startup costs discussed in the following section) financed with tax-exempt debt.

Figure 9 presents the estimated legal and other professional services costs; however, considering the experiences of other condemnation efforts, these estimates are likely to be conservative for an electrical system with the size and complexity of Pueblo.

Figure 9: The City's Estimated Transaction Costs

Transaction Costs	2024 (*$millions*)
Legal/Professional Services Costs	$10.0
Flotation Costs	$5.6
Total	**$15.6**

5.5 STARTUP COSTS

The City would also incur certain one-time startup costs that are necessary to operate a newly formed municipal electric utility. Specifically:

- Whether the City were to establish its own municipal utility to operate and manage the electric distribution or decides to outsource those activities, the City will incur costs

associated with starting the utility. Operations startup costs are based on the costs for starting a municipal utility (expressed on a $/customer multiplied by the number of customers in Pueblo) as recently projected by Boulder, Colorado as part of its formation of the municipal electric utility;[41]

- The City is assumed to require initial inventory, and the cost for inventory reflects 3.00% of the estimated RCNLD value of the distribution assets to be acquired;
- Since the City will need to have immediate access to capital to make the necessary replacements to the distribution system if ownership is assumed, it is assumed that the City would establish an initial capital expenditure fund to cover the first four years of capital expenditures reflecting a capital replacement rate of 2.70% – which is equivalent to BHE's composite depreciation rate in its 2011 depreciation study;
- The City would need to establish a debt service reserve fund roughly equivalent to one year of principal and interest associated with acquisition-related borrowings; and
- The City would require sufficient cash working capital upon starting operations, which is based on 45 days of working capital to cover power purchases, transmission expenses and O&M expenses.

Figure 10 summarizes the estimated startup costs, by category, that would be incurred by the City if it were to form a municipal electric utility.

Figure 10: The City's Estimated Startup Costs

Startup Costs	2024 (*$millions*)
Operations Startup Costs	$11.9
Inventory @ 3% of Total	$5.7
Initial Capital Expenditure Fund for First 4 Years	$20.4
Initial Debt Service Reserve	$11.8
Interest on Reserve Fund	$0.2
Working Capital	$12.7
Total	**$62.7**

[41] Startup costs reflect only the cost categories of facilities, fleet and half of the information technology expenditures estimated by Boulder, Colorado in its Financial Forecast Tool User Manual and Documentation, p. 27. The Preliminary Feasibility Study assumes that the City would not need to acquire additional real estate or buildings for office space, operations, or a service center.

5.6 TOTAL ESTIMATED COSTS FOR THE CITY TO ACQUIRE BHE'S DISTRIBUTION ASSETS

Figure 11 summarizes the estimated costs that would be incurred under the City Option to acquire BHE's distribution system in Pueblo.[42]

Figure 11: Summary of the City's Estimated Acquisition Costs

Cost Category	2024 (*$millions*)
Physical Assets	$188.5
Stranded Generation Costs	$79.9
Stranded Substation Costs	$27.2
Separation and Reintegration Costs	$28.3
Startup Costs	$62.7
Transaction Costs	$15.6
Total	**$402.0**

[42] It is important to recognize that this is a preliminary estimate that would need to be refined with actual and final cost information should the City decide to municipalize. In addition, the estimated cost to acquire BHE's utility property in the City herein does not assign any value associated with "going concern" that may be applicable if the City were to pursue municipalization. Also, these costs reflect what is referred to herein as the Base Case; alternative scenario analyses are discussed in Section 7.

6 PROJECTED OPERATING COSTS FOR THE CITY OPTION

The going forward costs of operating a municipal utility are referred to as the utility's "revenue requirement" or "cost of service." The Preliminary Feasibility Analysis assumes that an acquisition would occur at the start of 2024, and that the City will replicate the services and funding currently provided by BHE. The City's projected operating costs are evaluated over the 20-year Forecast Period (*i.e.*, 2024 through 2043).

The annual operating expenses that the City would incur include debt service costs associated with the acquisition costs to form the municipal utility, power supply costs (*i.e.*, the cost of purchased power and associated transmission expenses), O&M expenses, customer program expenses (*i.e.*, energy efficiency and energy assistance programs), and taxes/fees previously paid by BHE to the City and collected in utility rates. Many of these costs are affected by the number of customers served, the customers' total energy usage, and the system peak demand requirements.

For purposes of this analysis, it is assumed Pueblo's load growth would be 0.82% per year, consistent with the projection in BHE's 2016 Integrated Resource Plan for its entire Colorado service territory. In addition, utility customer count growth is assumed to be 0.22%, which reflects the compound annual growth rate in electric customers in Pueblo between 2010 and 2018. BHE's customers in the City as of the end of 2018 totaled 54,828.

6.1 DEBT SERVICE

As discussed, the City would need to raise capital to fund the total estimated acquisition costs in order to form a municipal utility (*i.e.*, the cost of the physical assets; stranded costs; separation and reintegration costs; transaction costs; and startup costs). The acquisition of investor-owned utility assets for the purposes of establishing a new municipal utility would likely be required to be financed with taxable debt. Typically, the financing structure is that the municipal utility debt would be guaranteed based on the revenues of the utility, not the general obligation of the taxpayers of the community. Therefore, the acquisition of the physical assets would be financed with revenue bonds. The other costs associated with the formation of a new municipal utility (*i.e.*, stranded costs, separation and reintegration costs, startup costs and transaction costs) would likely be financed with tax-exempt debt. It is assumed that both tax-exempt and taxable revenue bonds would be issued for a term of 30 years.[43]

Annual debt service costs would be determined by the amount to be financed, the relevant interest rate and the assumed credit rating of the new municipality. Since the Preliminary Feasibility Analysis assumes the acquisition of the assets would occur in 2024, it is necessary to estimate the financing costs at the time of the acquisition. The interest rate for taxable debt is based on the projected 30-year U.S. Treasury bond yield for 2021-2030 of 3.70% plus the spread between the historical average 30-year Treasury yield and

[43] Shorter financing terms could be achieved and may provide for lower borrowing costs; however, the annual debt service would be higher to reflect the prepayment of principal over fewer years.

the average Moody's AA-rated utility debt yield, or a historical spread of 0.97%.[44] The result of this analysis is a projected taxable bond rate of approximately 4.67%.

The interest rate differential (spread) between taxable and tax-exempt debt is based on a comparison of actual taxable and tax-exempt debt issuances. Comparing bond rates over the last several years for taxable and tax-exempt debt issued by the same Colorado municipal utility for the same duration normalizes the results for differences in interest rates due to varying borrowing lengths and utility credit ratings. This analysis indicates that the historical spread between taxable and tax-exempt debt for issuances of similar term and credit rating is 86 basis points. Based on this historical spread, it is assumed that the projected tax-exempt debt rate is 3.81%.

6.2 GENERATION AND TRANSMISSION EXPENSES

Purchased Power

Acquiring power to serve the municipality's electric customers, either through third-party purchases or through self-generation, is the largest component of the revenue requirement for any municipal electric utility. There are two components to the purchased power costs that are used to derive Pueblo's estimated "all-in" cost of power in the City Option: (i) energy-only costs; and (ii) capacity, ancillary, and other charges.

Energy-Only Costs

The most recent independent energy price forecast for the Colorado-East region produced by ABB is used to estimate the cost of the City's future energy requirements over the Forecast Period. This electric price forecast is the same one previously referenced in the estimation of the stranded generation costs that the City would incur if it were to municipalize. ABB defines various regional pricing areas within its reference case forecast, and the energy prices for the Colorado-East pricing zone are used as the zone most relevant to Pueblo. The energy prices in the reference case forecast are expressed in real or constant dollars as of the base year of the forecast (*e.g.*, energy prices in the Spring 2019 Reference Case Forecast are provided in 2019 dollars). For the analysis herein, the energy prices specified in the reference case forecast are adjusted for inflation to establish nominal energy prices, with the inflation estimate reflecting the average change in the Consumer Price Index as published by the Blue Chip Financial Forecast. The Blue Chip Financial Forecast publishes consensus estimates of projected financial and economic indicators that are based on the projections of up to 50 industry analysts. The inflation rate forecast is 2.10% as of the development of this report.[45]

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[44] The historical 30-year treasury yield averaged 2.97 percent from January 1, 2017 through July 31, 2019 (Bloomberg Finance). The historical Moody's AA-rated utility debt yield averaged 3.94 percent (Bloomberg Finance). The difference between these two indicates a historical spread of approximately 0.97 percent. The projected yield on the 30-year U.S. Treasury Bond of 3.70 percent is derived from Blue Chip Financial Forecasts, Vol. 38, No. 6, June 1, 2019, at p. 14.

[45] Blue Chip Financial Forecast, Vol. 38, No. 6, June 1, 2019, p. 14 (10-year period 2021 through 2030).

Key Power Acquisition Considerations

The electricity that is provided to customers is measured in both capacity and energy.

Capacity: *the maximum output that an electric generator can physically produce; typically measured in MW*

Energy: *the amount of electricity produced by a generator over a specific period of time; typically measured in kWh or MWh*

Reserve Margin: *the additional amount of capacity in excess of customers' peak demand necessary to account for generation that is unable to produce electricity at all or can only do so at a reduced level*

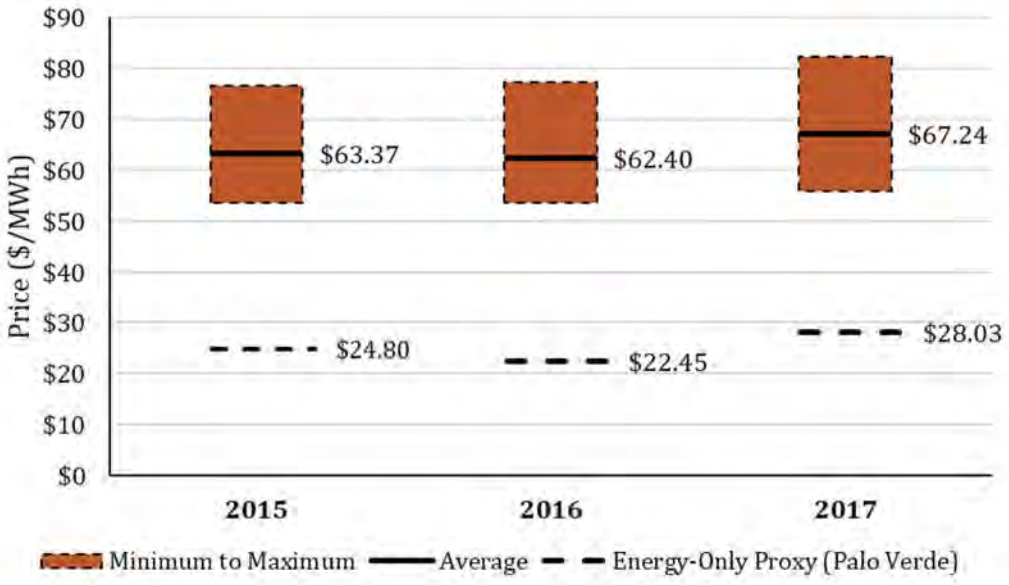
Investor-owned electric utilities such as BHE ensure that they have sufficient capacity in order to generate the energy to meet the peak demands and variable energy requirements of their customers throughout the year. This capacity can be from generating facilities that are owned by the utility and/or from facilities from which they have a firm contractual commitment. It is common practice for utilities to also include a reserve margin when planning for the amount of capacity required. The reserve margin is an additional amount of capacity in excess of their customers' peak demand in order to cover periods in which one or more generators are either unable to produce electricity or can only do so at a reduced level.

If the City were to municipalize, it is important that future commitments to acquire power provide Pueblo the right not just to energy in the market, but are backed by sufficient generation capacity to ensure that the electricity will be able to be delivered to the City, even during constrained periods, and that the price of acquiring electricity during any constrained periods will not subject the City to unexpected increases in pricing.

Capacity, Ancillary and Other Charges

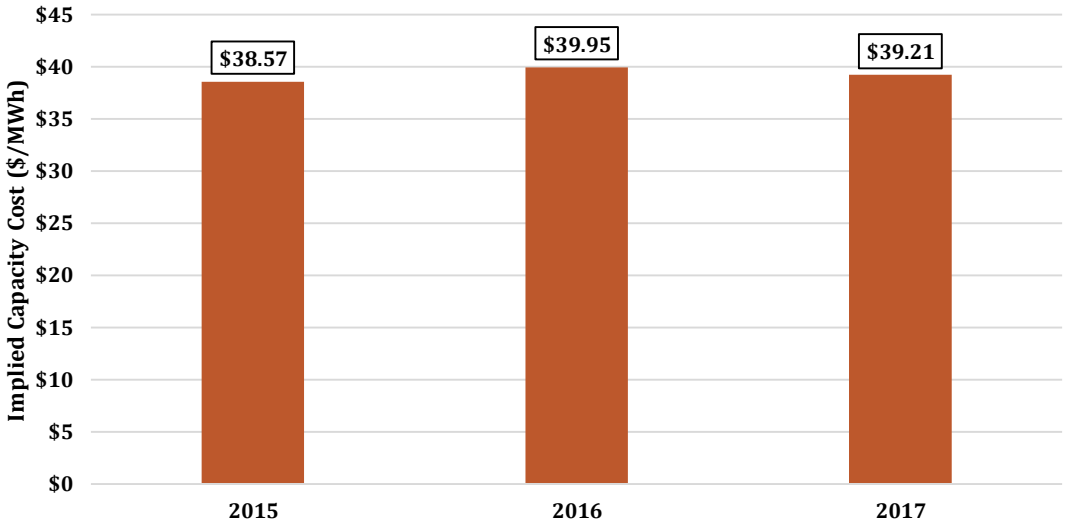
The cost of capacity, ancillary, and other charges (hereinafter referred to for convenience as simply "capacity") are estimated by reviewing the actual historical purchased power costs reported by other municipal electric utilities in Colorado. Specifically, the analysis starts with the all-in power supply costs reported by 7 municipal utilities in Colorado (*i.e.*, Center, Estes Park, Fort Collins, Glenwood Springs, Gunnison, Lyons, and Oak Creek) in their respective financial statements for the three most recent years for which data is currently available (*i.e.*, 2015-2017). The power supply costs on a $/MWh basis for those 7 municipal electric utilities is summarized in Figure 12. Since the total power supply costs for these municipalities is not separately reported for energy versus capacity versus transmission, it is assumed that the energy costs in the region applicable to each of the seven municipal Colorado electric utilities is the annual average around-the-clock price at the Palo Verde hub for each of these same years, also shown in Figure 12.

Figure 12: Municipal Total Power Supply Cost v. Energy-Only Cost



After deducting the cost associated with energy from the total, the remaining portion of the reported power supply costs by these municipalities then relates to capacity and transmission costs. The resulting estimates for the cost of capacity and transmission for these municipal utilities are summarized in Figure 13.

Figure 13: Implied Average Cost of Capacity and Transmission



As shown, the cost of capacity and transmission was relatively stable over the most recent three years. Since it is not reported what proportion of the costs in Figure 13 are related to capacity versus transmission, for purposes of the Preliminary Feasibility Analysis, the cost of capacity for the City is estimated at $20/MWh in 2019, and which is escalated to the first year of the Forecast Period and then escalated throughout the Forecast Period.

Transmission Expense

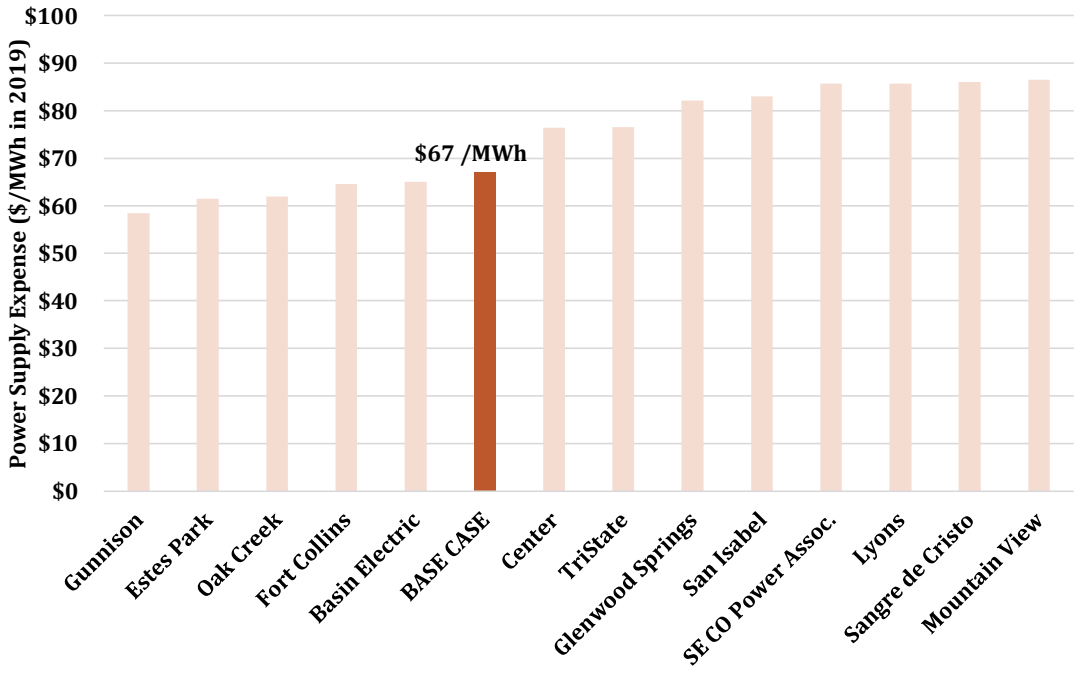
The City would also incur costs associated with the use of BHE's open access transmission system to deliver power to the interconnection with the City. Transmission expense for the City is determined by applying BHE's 2018 transmission expense for its Colorado service territory (expressed on a $/MW basis of peak load) to the peak load of Pueblo.[46] It is assumed that the City's peak load would grow at the same rate as its annual load (*i.e.*, 0.82% per year) throughout the Forecast Period.

Total Generation and Transmission Expense

The total estimated power supply costs under the City Option combines (i) the energy and capacity components of the generation costs (expressed on a $/MWh basis) discussed above multiplied by the projected Pueblo wholesale electric demand (*i.e.*, the retail sales grossed up for line losses) in each year of the Forecast Period; and (ii) the estimated transmission expense.

Overall, the estimate of the City's total annual generation and transmission expense is conservative as compared with the most recently reported annual power supply expenses for other Colorado municipal utilities. As shown in Figure 14, the total generation and transmission cost is consistent with the cost benchmarks of other municipal utilities in Colorado.

Figure 14: Comparison of Total Power Supply (*i.e.*, Generation + Transmission) Expense



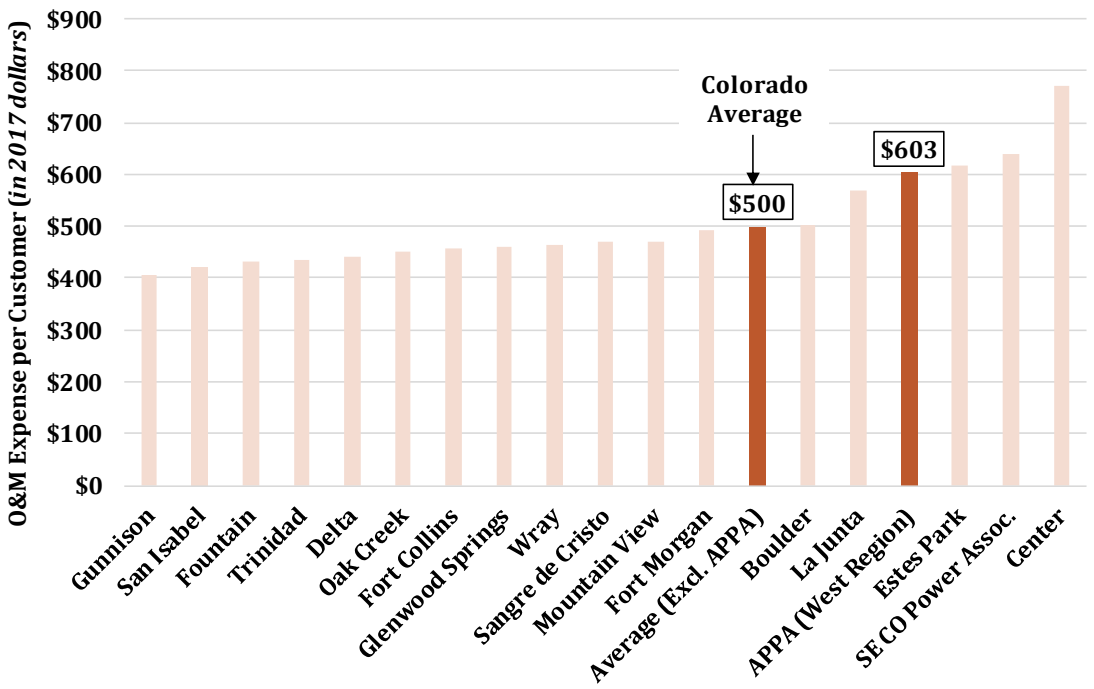
[46] BHE's system-wide transmission expense in 2018 reflects: (1) the 2015 transmission-related revenue requirement of approximately $21.4 million per the Company's most recent rate case; and (2) the incremental revenue requirement of approximately $4.0 million associated with the Company's 2016-2018 transmission investments per the Company's current Transmission Cost Adjustment tariff.

6.3 O&M EXPENSES

The City would also be required to operate and maintain its electric distribution system if it were to operate the electric utility. To estimate the O&M expenses in the City Option, the O&M expenses per customer as reported by other municipal utilities, both in Colorado and throughout the western U.S., as well as the cooperative utilities in southeastern Colorado, are used as a benchmark. The analysis reflects the most recently reported financial information for 12 municipal electric utilities in Colorado[47] and 5 cooperative electric utilities surrounding Pueblo.[48] The analysis also considers an American Public Power Association ("APPA") 2017 report that includes national and regional financial benchmarks of selected public power utilities across the U.S., including the West Region that encompasses the City.[49]

Figure 15 summarizes the results of the O&M benchmarking analysis. As shown, the average O&M costs per customer are lower in the Colorado benchmarking analysis when compared to the O&M costs reported in the APPA study.

Figure 15: Range of O&M Expenses



[47] These municipalities are Estes Park, Fountain, Glenwood Springs, Center, Fort Collins, Fort Morgan, Gunnison, La Junta, Oak Creek, Trinidad, and Wray. In addition, the O&M expense as projected by the City of Boulder is also reflected. Data was available for 5 additional municipalities (*i.e.*, Aspen, Burlington, Frederick, Lamar, Lyons); however, since the O&M expense per customer was substantially higher than the other municipalities, the data for these 5 communities was excluded from the analysis.

[48] These cooperative utilities are Delta, Mountain View, San Isabel, Sangre de Cristo, and Southeast Colorado Power.

[49] APPA, Financial and Operating Ratios of Public Power Utilities, December 2017, p. 24, Table 10, "West" region.

For purposes of the Preliminary Feasibility Study, the O&M expenses in the first year of the Forecast Period for the City Option reflect the average O&M expenses per customer in the Colorado benchmarking analysis multiplied to the number of customers in Pueblo. The initial year O&M expenses are escalated at inflation throughout the Forecast Period, and also are adjusted to account for the estimated growth in the number of customers in Pueblo over the Forecast Period.

6.4 ENERGY EFFICIENCY PROGRAM EXPENSES

As a stand-alone municipal utility, the City will not be required to provide energy efficiency programs to its customers; however, existing residential and business customers within the City have taken advantage of BHE's energy efficiency programs. Participating residential and business customers in Pueblo have received rebates and other investments through BHE, and accordingly, it is assumed that a similar level of energy efficiency offerings would be provided in the City Option as compared to what is currently provided by BHE.

BHE currently projects that it will spend approximately $6.5 million per year system-wide in Colorado on energy efficiency measures in 2019-2021.[50] The system-wide energy efficiency budget is allocated to Pueblo and the remainder of the system based on three allocation factors: Pueblo's share of BHE's total system annual load, peak demand, and number of customers. Each are these metrics are considered in the allocation since each is typically a function of the energy efficiency expense incurred. Figure 16 summarizes the allocation factors. The Year 1 energy efficiency expense is then escalated at inflation throughout the Forecast Period.

Figure 16: Energy Efficiency Expense Allocation

Description	2018 Load (MWh)	2018 Peak Demand (MW)	2018 Customers (Count)	Average Allocator (%)
Total System	1,969,683	410.84	96,716	
Pueblo Only	788,391	178.99	54,828	
% of BHE Budget Allocated to Pueblo	**40.0%**	**43.6%**	**56.7%**	**46.8%**

6.5 LOW-INCOME ASSISTANCE PROGRAM EXPENSES

It is assumed that a newly formed municipal electric utility would continue to provide the same level of support to low-income electric customers in the City Option as would be provided in the BHE Option. From 2015 through 2018, BHE provided an annual average of $213,000 in low-income assistance to customers in Pueblo. The 2018 program contribution, escalated at inflation, is used for

[50] Black Hills Colorado Electric Inc. d/b/a BHE, Energy Efficiency (Demand Side Management) Plan, 2019-2021, p. 7. The amounts related to administrative and general expenses (*e.g.*, expenses related to the design, administration, marketing, and evaluation of the program) have been removed from that projection in order to eliminate potential duplication of those same costs as part of the non-fuel O&M expenses. Accordingly, the starting amount of energy efficiency costs for purposes of this analysis total approximately $5.6 million exclusive of these A&G-related expenses in the energy efficiency budget.

the low-income assistance expense Year 1, which is then escalated throughout the Forecast Period. Charitable contributions made by BHE to organizations in Pueblo have not been included in the analysis.

6.6 PROPERTY TAXES AND OTHER FEES

As a private corporation, BHE pays property taxes on the assessed value of its assets located in Pueblo. In addition, BHE also pays a franchise fee and undergrounding fees to the City. These taxes and fees are included as expenses in BHE's revenue requirement and are reflected in the calculation of distribution rates paid by all BHE customers. These taxes and fees paid by BHE benefit the City, and if Pueblo were to own and operate an electric utility, BHE would no longer pay such taxes and fees to the City. Therefore, in order to continue to fund the City operations at the existing levels, it is necessary to also assume that the municipal electric utility would provide a "payment in lieu of taxes" to the City's general fund to replace this revenue source that is currently supplied through BHE's rates. In total, the property taxes and fees paid by BHE to the City in 2018 totaled approximately $4.7 million. For the City Option, it is assumed that the 2018 property taxes and fees, as escalated at inflation throughout the Forecast Period, represents the cost to the City to replace such revenue from BHE.

Fees Impact

By moving to a municipal electric utility, Pueblo would forego an estimated $5.4 million (in 2024 dollars) in property taxes and fees paid by BHE to the City, which is more than the City's 2019 budgeted debt service payment.

Source: Pueblo 2019 City Budget, p. E-1.

In addition to the $4.7 million in property taxes and fees paid by BHE to the City in 2018, BHE also paid approximately $6 million in taxes to Pueblo County in 2018, a portion of which are allocated to the City. The taxes paid by BHE to Pueblo Country from which the City receives benefit have not been included as a cost in the City Option, even though BHE's payments to the County, and thus the City, would be eliminated and therefore this source of funds would need to be replaced by the City.

6.7 PROJECTED REVENUE REQUIREMENT FOR THE CITY OPTION

Based on the analysis and assumptions described herein, Figure 17 summarizes the projected revenue requirement for the City Option over the 20-year Forecast Period.

Figure 17: Projected Municipal Revenue Requirement for the City Option

	Year 1 (2024)	Year 5 (2028)	Year 10 (2033)	Year 15 (2038)	Year 20 (2043)
Debt Service					
Principal	$6.9	$8.6	$11.0	$14.3	$18.5
Interest	$16.2	$16.0	$14.9	$13.3	$10.8
Subtotal	**$23.1**	**$24.5**	**$26.0**	**$27.6**	**$29.3**
Energy-Related Expenses					
Generation	$52.1	$63.6	$77.0	$92.2	$106.3
Transmission	$15.6	$19.6	$26.0	$34.6	$46.0
Subtotal	**$67.7**	**$83.2**	**$103.0**	**$126.8**	**$152.4**
O&M Expense					
Subtotal	**$32.1**	**$35.2**	**$39.5**	**$44.3**	**$49.7**
Assistance Programs					
Energy Assistance Program	$0.3	$0.3	$0.3	$0.3	$0.4
Energy Efficiency	$2.9	$3.1	$3.4	$3.8	$4.2
Subtotal	**$3.1**	**$3.4**	**$3.8**	**$4.2**	**$4.6**
Taxes and Fees					
Payments in Lieu of Taxes	$1.0	$1.1	$1.3	$1.4	$1.5
Franchise Fee	$3.7	$4.1	$4.5	$5.0	$5.6
Undergrounding Fee	$0.6	$0.7	$0.7	$0.8	$0.9
Subtotal	**$5.4**	**$5.9**	**$6.5**	**$7.2**	**$8.0**
Total Cost of Municipal Ownership					
Total	**$131.4**	**$152.1**	**$178.7**	**$210.0**	**$244.0**

7 PROJECTED FUTURE COST OF THE BHE OPTION

The assessment of the financial feasibility of a City municipal electric utility also depends on the projected revenue requirement, and thus electric rates, that Pueblo customers would pay should BHE continue to serve Pueblo (*i.e.*, the BHE Option). This section summarizes the assumptions used to estimate the future electric cost to Pueblo customers under the BHE Option.

To determine BHE's projected initial year revenue requirement for the BHE Option, BHE's system-wide average retail electric rate in 2018 is multiplied by Pueblo's 2018 load. Specifically, as reported in the FERC Form No. 1, BHE's system-wide average retail electric rate in 2018 was $126.15 per MWh,[51] which is then multiplied by Pueblo's 2018 retail sales of 788,391 MWh. The resulting revenue requirement is then separated into three components: (1) the generation revenue requirement; (2) the transmission revenue requirement; and (3) the distribution revenue requirement.

Generation Revenue Requirement

BHE's power needs are met through a combination of gas-fired generating resources, renewable energy resources, power purchase agreements, and market purchases. Figure 18 reflects BHE's historical system average generation cost for the last five years based on data reported by the Company in its FERC Form No. 1. As shown, BHE's system average generation cost per MWh is applied to the load in Pueblo to derive the estimated portion of BHE's overall historical generation cost attributable to Pueblo.

Figure 18: BHE's Historical Generation Cost

	2016	2017	2018
Generation Revenue Requirement - BHE Colorado	$162,901,599	$152,605,035	$151,767,310
Total BHE System Sales (MWh)	1,923,650	1,901,235	1,969,683
BHE System Generation Cost ($/MWh)	$84.68	$80.27	$77.05
Pueblo Retail Load (MWh)	786,788	765,896	788,391
Generation Revenue Requirement - Pueblo Only	**$66,627,999**	**$61,475,609**	**$60,746,840**

To project BHE's future generation revenue requirement, the analysis starts with the 2018 cost data for each of BHE's generation resources as reported in the 2018 FERC Form No. 1, which is then projected to reflect changes over the Forecast Period in (1) the composition of the Company's generation portfolio (*i.e.*, the addition of new generating resources and the expiration of existing PPAs); (2) the cost of the Company's various generating resources (*e.g.*, changes in the price of fuel and the price of the PPAs); and (3) the Company's load. Regarding changes in the composition of the generation resource portfolio, the Company's public filings indicate that, for example, the Company will begin purchasing in 2019 the output of the Busch Ranch II wind farm through a PPA. In addition, the PAGS PPA, which represents a material portion of BHE's overall generation portfolio, expires at the end of 2031. The projected costs of the Company's owned generation resources assume that fuel expenses reflect future changes in natural gas prices as projected by ABB in its reference case forecast, O&M expenses increase with inflation, and that return, depreciation and income taxes are stable.

[51] Black Hills Colorado Electric, LLC, 2018 FERC Form 1, page 304.

Upon the expiration of the PAGS PPA, the analysis assumes that BHE replaces the lost output with energy and capacity at the then-prevailing market rate to meet its load. Due to the difference between the cost of energy purchased through the PAGS PPA and the market price of energy, the expiration of the PAGS PPA creates a step-change reduction in the cost of BHE's generation and therefore BHE's estimated revenue requirement in 2032.

Transmission Revenue Requirement

It is assumed that the transmission component of BHE's revenue requirement would equal Pueblo's projected transmission expense as reflected in the City Option. As previously discussed, the transmission expense in the City Option would reflect the use of BHE's open access transmission system, and thus transmission expense in both the BHE Option and the City Option would be the same.

Distribution Revenue Requirement

Changes to BHE's retail rates are approved by the CPUC and occur primarily through rate proceedings that reflect changes in the cost of providing service, the number of customers and the energy demand of the customers. Changes to the costs of providing electric service determine the revenue requirement that rates will be designed to collect, while changes to the number of customers and energy demand affect how the revenue requirement is allocated to each class of customers (*e.g.*, residential, commercial, industrial) and, in turn, the calculation of the specific rates that appear on customer bills.

The distribution component of BHE's 2018 revenue requirement is calculated by subtracting the sum of BHE's 2018 generation and transmission revenue requirement as described above from BHE's 2018 total revenue requirement. Increases in BHE's distribution revenue requirement are projected over the remainder of the Forecast Period by estimating the average annual increase in BHE's base distribution rates. Specifically, it is estimated that BHE's base distribution rates would increase 2.10% per year, which reflects the projected inflation rate in the most recent Blue Chip Financial Forecast.[52] This assumed growth rate for BHE's distribution rate is consistent with both (i) the historical compound annual growth rate in BHE's base distribution rates; and (ii) an analysis of historical trends in rate proceedings in the Western Electricity Coordinating Council ("WECC") region.

First, from 2008 (*i.e.*, the year in which BHE acquired the electric distribution system in Colorado from Aquila) through 2019, BHE has had four authorized distribution rate increases. In addition, BHE's management recently indicated that it does not expect to file for a distribution base rate increase in Colorado for the next five years.[53] Therefore, assuming there is no distribution rate increase at least until 2024, BHE's compound annual distribution growth rate from 2008 through 2024 is 1.46%, which is lower than the long-term projection of inflation used herein for the feasibility analysis.

Second, the projected growth in BHE's distribution revenue requirement is also supported by historical rate case activity in the WECC region more broadly. Figure 19 illustrates the average frequency of rate proceedings and the magnitude of rate changes in the WECC region based on an analysis of over 400

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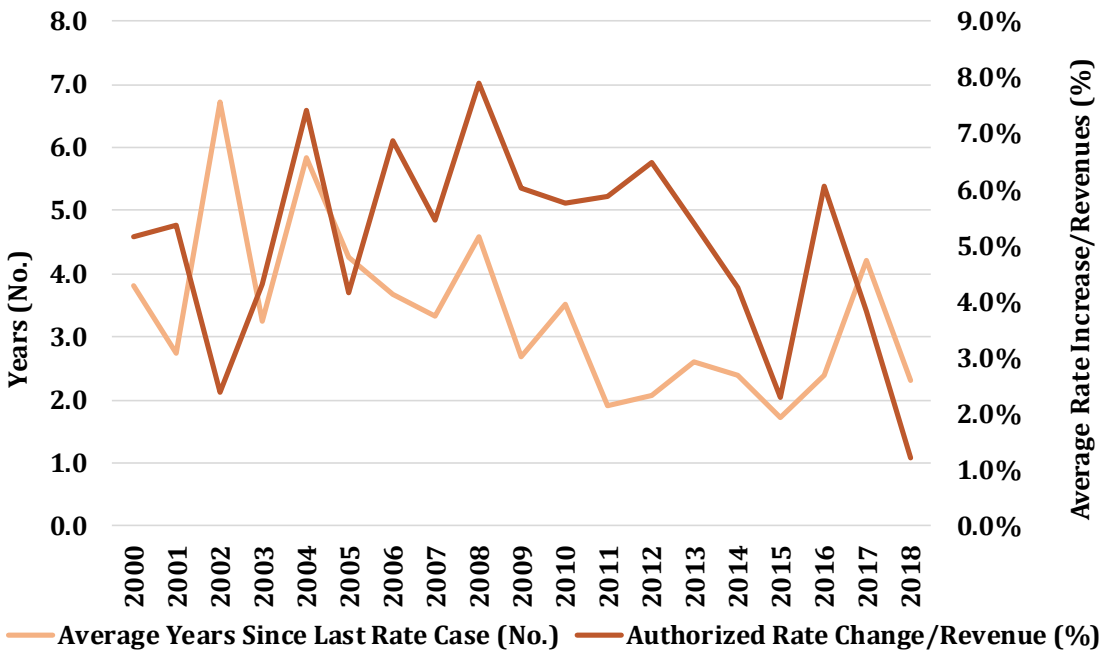
52 Blue Chip Financial Forecast, Vol. 38, No. 6, June 1, 2019, p. 14 (10-year period 2021 through 2030).

53 Thompson Reuters Transcript, Q2 2019 Black Hills Corp. Earnings Call, August 6, 2019, p 14.

completed rate proceedings.[54] From 2000 to 2018, the average frequency of an electric rate proceeding was approximately 3 years, with the average authorized rate increase being 5.60%, which on an annual average basis is lower than the average annual rate of 2.1% that is assumed for BHE's future distribution rate increases herein.

Figure 19: Average Frequency and Magnitude of Electric Rate Changes in Western U.S.



It is important to note that the assumptions regarding projected future BHE rate changes for this analysis are based solely on the analysis of historical regulatory trends for BHE, inflation projections, BHE's public statements regarding future rates and the analysis of rate proceedings in the WECC region. This analysis is not intended to and ***does not*** reflect a commitment by BHE as to any potential future changes in retail electric rates for the Company's distribution system in Colorado.

54 S&P Global Market Intelligence. Analysis includes utility rate proceeding activity in the following states in WECC: Arizona, Colorado, California, Idaho, Montana, New Mexico, Nevada, Oregon, Utah, Washington, and Wyoming.

8 PRELIMINARY FEASIBILITY STUDY FINANCIAL RESULTS

The financial feasibility of the City Option is assessed by comparing the projected revenue requirement of municipal ownership in the City Option to the estimated revenue requirement of continued service by BHE under the BHE Option. The annual cost differences between the City Option and the BHE Option over the Forecast Period are then discounted at the City's estimated debt rate to determine the net present value benefit or cost to the City of municipalization. Specifically, for each year of the comparison, the discount rate reflects the City's estimated composite debt rate associated with the mix of taxable and tax-exempt debt then in effect. The net present value is calculated as of the year of an assumed transaction. The financial feasibility of the City Option and BHE Option described in Sections 5, 6 and 7 are considered the Base Case for this analysis. As discussed below, two additional scenarios – a High Cost Scenario and a Low Cost Scenario – are also conducted.

8.1 BASE CASE RESULTS

Figure 20 compares the Base Case revenue requirement under the City Option as discussed in Section 6 relative to the BHE Option beginning in 2024 as discussed in Section 7. As shown, there is estimated to be a significant net present value financial cost from municipal ownership and operation of the electric utility as compared with a continuation of service with BHE during the Forecast Period.

Figure 20: Results of the Base Case Scenario

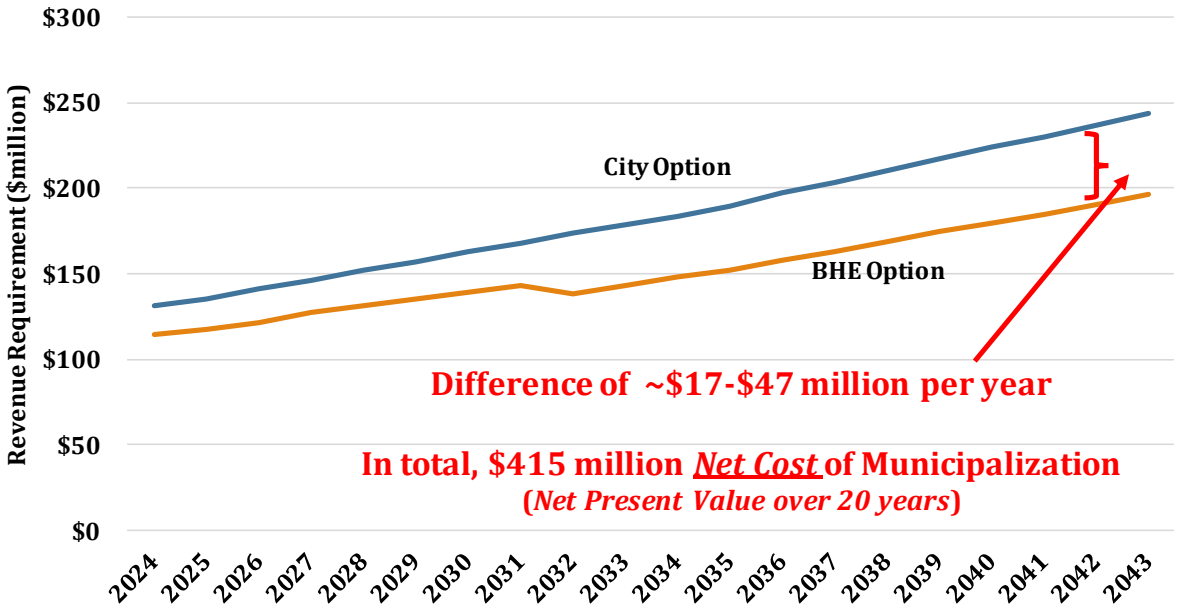
	Year 1	Year 5	Year 10	Year 15	Year 20
Black Hills Energy					
BHE Option Revenue Requirement	**$114.5**	**$131.4**	**$143.2**	**$168.6**	**$196.7**
Pueblo Municipal Utility					
Debt Service (Principal & Interest)	$23.1	$24.5	$26.0	$27.6	$29.3
Energy-Related Expenses	$67.7	$83.2	$103.0	$126.8	$152.4
O&M Expenses	$32.1	$35.2	$39.5	$44.3	$49.7
Assistance and Efficiency Programs	$3.1	$3.4	$3.8	$4.2	$4.6
Taxes and Fees	$5.4	$5.9	$6.5	$7.2	$8.0
City Option Revenue Requirement	**$131.4**	**$152.1**	**$178.7**	**$210.0**	**$244.0**
Estimated Annual Benefit/(Cost) to City	($16.9)	($20.8)	($35.5)	($41.4)	($47.3)
NPV of Benefit/(Cost) Over Initial 20 Years	**($414.5)**				

Figure 21 graphically presents the numerical results of the comparison of the City Option and BHE Option in the Base Case scenario. As shown, the revenue requirement (*i.e.*, electric costs to be recovered from Pueblo customers) is projected to be lower under the BHE Option as opposed to the City Option, meaning that switching to a municipal electric utility would result in a net cost to Pueblo electric customers.

As discussed previously and as shown in Figure 21, the projected cost of future electric service to Pueblo customers under the BHE Option decreases in 2032 upon the expiration of the PAGS PPA. Once the PAGS

PPA expires, the analysis assumes that BHE replaces the lost output with energy and capacity at the then-prevailing market rate to meet its load. Due to the difference between the cost of energy purchased by BHE through the PAGS PPA and the projected market price of energy, the expiration of the PAGS PPA creates a step-change reduction in the generation component of BHE's estimated revenue requirement in 2032. The projected cost under the City Option does not have a similar step change reduction since, as discussed previously, the stranded generation costs that would be incurred by the City if it were to form a municipal utility are assumed to be determined at the time of the City's acquisition of BHE's electric distribution system and then financed over a 30-year period.

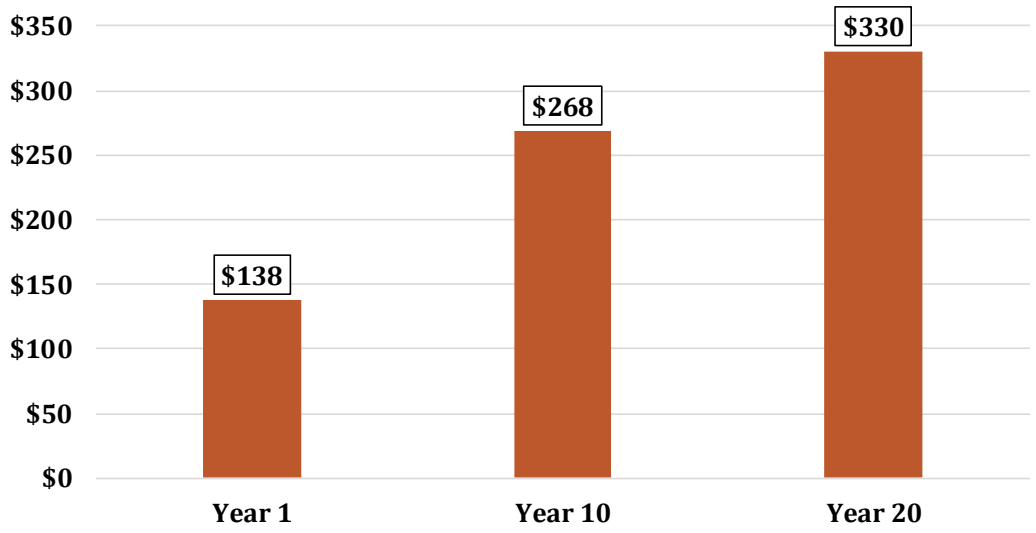
Figure 21: Base Case Rate Comparison



Because there is estimated to be a net cost to the City if it were to municipalize, electric customers would be projected to pay more than if service were to continue to be provided by BHE. Figure 22 presents the additional annual cost to the average residential electric customer if the City were to municipalize.[55]

[55] The average bill increases reflect the additional cost of municipalization as estimated in this Preliminary Feasibility Study divided by the total usage in Pueblo, then multiplied by the average usage of a residential customer in Pueblo.

Figure 22: Estimated *Annual Average* Bill Increase for Residential Customers If Pueblo Were to Form Its Own Municipal Utility



8.2 SCENARIOS

In addition to the Base Case, two additional scenarios are developed to reasonably bound the results of the study (referred to herein as the "Low Cost" and "High Cost" scenarios) and provide insights into the range of potential outcomes from establishing a municipal electric utility. The High Cost Scenario assumes that the costs for municipal acquisition and ownership would be higher than estimated in the Base Case, while the Low Cost Scenario assumes that those costs would be lower than estimated in the Base Case (*i.e.*, the "Low Cost Scenario"). The changes in each scenario reflect the combination of the changes to all of the key assumptions identified and that all changes are in the same direction (*i.e.*, in the High Cost Scenario, all changes to these assumptions increase the costs of municipal acquisition and ownership in the City Option and likewise decrease those costs in the Low Cost Scenario relative to the Base Case). All changes to operating cost assumptions represent a reasonable range of cost factors based on other experiences with municipal utility ownership and operation.

Figure 23 provides a comparison of the assumptions that are reflected in the Low Cost and High Cost scenarios relative to the Base Case.

Figure 23: Key Scenario Assumptions

Assumption	Base Case Scenario	High Cost Scenario	Low Cost Scenario
Municipal Utility Start Date (Year)	2024	2029	2022
Energy + Capacity Price ($/MWh; 2024)	$58.65/MWh	+$10/MWh	-$10/MWh
O&M Costs ($/customer, in 2024)	$578	$698	$487
Acquisition Costs (in 2024)	$188.5 million	+$50 million	-$50 million
BHE Distribution Rate	2.1%	1.1%	3.1%

Each of the assumptions that vary in the High Cost and Low Cost Scenarios are described below:

Municipal Start Date: The future costs of operating a municipal electric utility is a function of the time that would be associated with a transition from BHE operation of the electric utility to a City municipal electric utility. The uncertainty with respect to timing is attributable to the time required for court, regulatory and other approvals as part of the municipalization process. As described previously, the duration of the effort to establish a municipal electric utility can be many years depending on the regulatory and legal process, and extent of disagreement between the parties. The costs to be incurred both with the acquisition and operation of the utility property will increase as the duration is extended due to higher legal and consulting fees leading up to an acquisition, and continued escalation of both capital and operating costs. Assuming the transition occurs in 2024 in the Base Case, the Low Cost Scenario assumes a 2022 start date, and the High Cost Scenario assumes a 2029 start date.

Energy + Capacity Price: The generation costs in the High and Low Cost Scenarios are based on a $10/MWh band above and below the Base Case.

O&M Expenses: As discussed, the City Option in the Base Case reflects the average O&M expenses per customer of various Colorado municipal and cooperative utilities (*i.e.*, $500/customer in 2017 dollars). In contrast, the Low Cost Scenario reflects the O&M expense per customer of San Isabel only, which is on the low end of all of the municipality and cooperative utilities in Colorado reviewed (*i.e.*, $421/customer in 2017 dollars). The High Cost Scenario reflects the "Mean (weighted)" value for the West region as published in the 2017 APPA study (*i.e.*, $603/customer in 2017 dollars). In each scenario, the O&M expense per customer in 2017 is inflated to the start of the Forecast Period in each specific scenario (*i.e.*, 2022 in the Low Cost Scenario and 2029 in the High Cost Scenario) and then inflated throughout the 20-year Forecast Period.

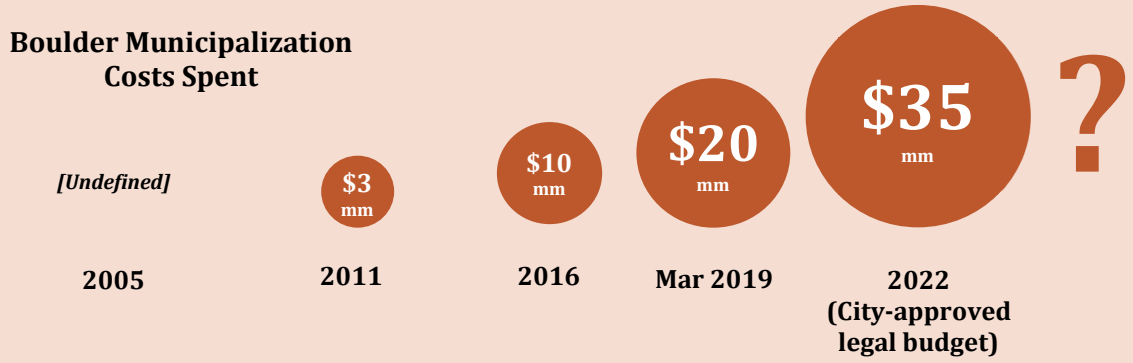
Acquisition Costs (excluding Physical Asset Costs): The acquisition costs in the High and Low Cost Scenarios are based on +/- $50 million relative to the Base Case. The change in acquisition costs in these scenarios are assumed to be related to the non-physical asset costs, and thus financed by the tax-exempt debt.

BHE Distribution Rate: As discussed, the BHE distribution rate in the Base Case is assumed to increase at 2.1% annually throughout the Forecast Period. The BHE distribution rate is

assumed to increase 3.1% annually throughout the Forecast Period in the Low Cost Scenario (meaning in this scenario the costs of municipalization for Pueblo are lower, and the projected future BHE rate in comparison is higher) and is assumed to increase 1.1% annually in the High Cost Scenario.

Cost Uncertainties of the Municipalization Process

As noted, the municipalization process can take years, and throughout the process costs can escalate significantly. For example, Boulder, Colorado's expenses associated with its ongoing municipalization process have increased significantly. In 2017, Boulder approved a budget of $35 million through 2022 toward its municipalization effort, though the municipalization effort has not been yet been completed. For context, Boulder has a similar number of customers as Pueblo (although nearly twice the electric load), and $35 million in municipalization-related costs alone is roughly the equivalent of 40% of Pueblo's 2019 budgeted revenues for the City.



The High Cost Scenario indicates a substantially higher net cost to Pueblo of municipalization over the Forecast Period relative to the Base Case. As presented in Figure 24, the High Cost Scenario results in a net present value cost to Pueblo over the 20-year Forecast Period of over $800 million.

Figure 24: Results of the High Cost Scenario

	Year 1	Year 5	Year 10	Year 15	Year 20
Black Hills Energy					
BHE Option Revenue Requirement	**$131.5**	**$146.4**	**$171.0**	**$198.1**	**$239.1**
Pueblo Municipal Utility					
Debt Service (Principal & Interest)	$23.6	$25.1	$26.8	$28.6	$30.6
Energy-Related Expenses	$98.3	$115.8	$141.6	$169.4	$203.8
O&M Expenses	$43.4	$47.6	$53.4	$60.0	$67.3
Assistance and Efficiency Programs	$3.5	$3.8	$4.2	$4.6	$5.1
Taxes and Fees	$6.0	$6.5	$7.2	$8.0	$8.9
City Option Revenue Requirement	**$174.8**	**$198.8**	**$233.2**	**$270.6**	**$315.6**
Estimated Annual Benefit/(Cost) to City	($43.3)	($52.4)	($62.2)	($72.5)	($76.5)
NPV of Benefit/(Cost) Over Initial 20 Years	**($807.6)**				

While the Low Cost Scenario assumes that the costs of municipalization will be lower than the Base Case, and that BHE's distribution rates will increase in the future at a faster rate than in the Base Case, the results still indicate a net cost of Pueblo customers associated with municipalization. As shown in Figure 25, the Low Cost Scenario results in a net present value cost to Pueblo over the 20-year Forecast Period of over $135 million.

Figure 25: Results of the Low Cost Scenario

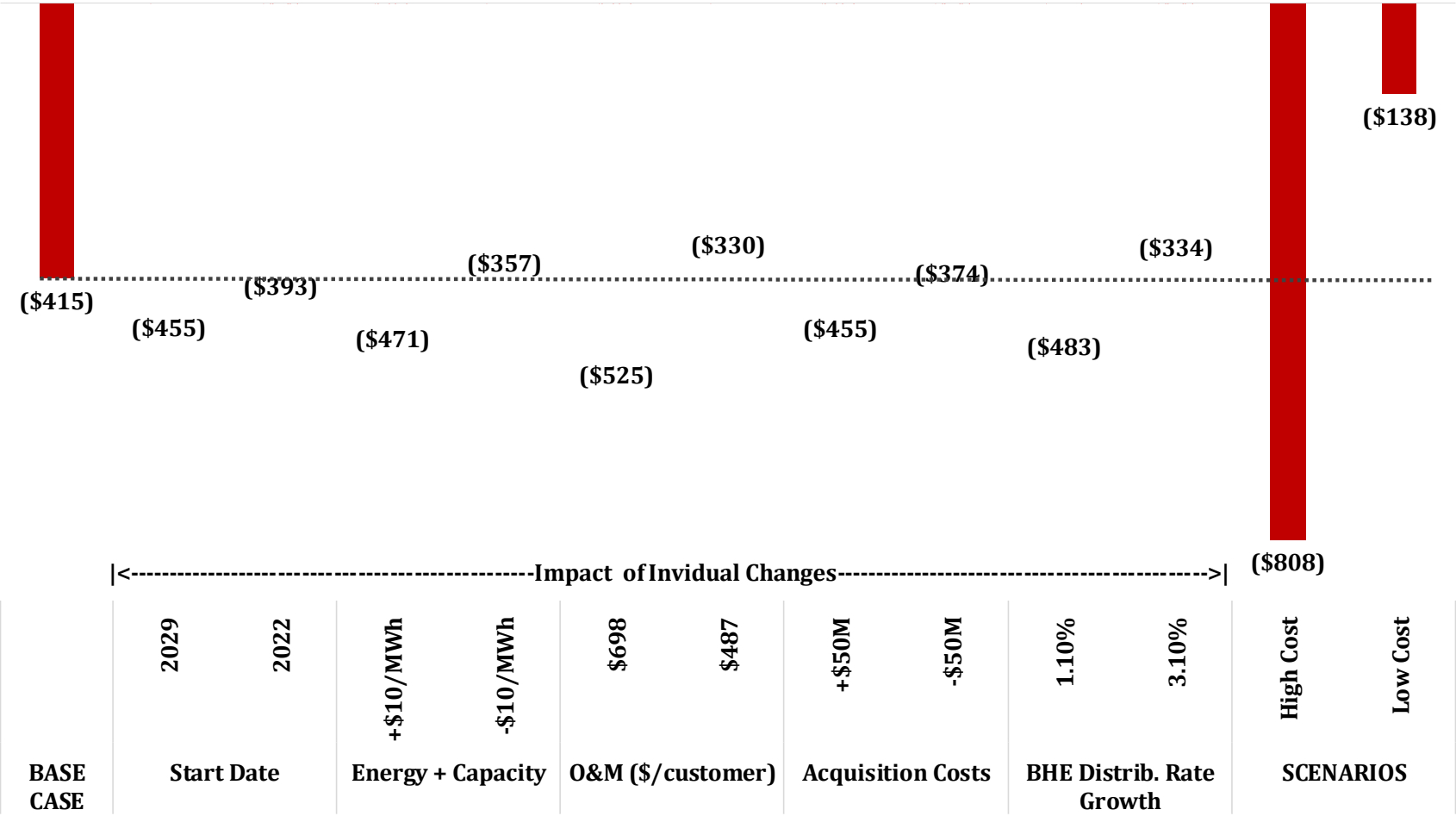
	Year 1	Year 5	Year 10	Year 15	Year 20
Black Hills Energy					
BHE Option Revenue Requirement	**$109.2**	**$123.8**	**$147.9**	**$156.2**	**$185.1**
Pueblo Municipal Utility					
Debt Service (Principal & Interest)	$24.6	$25.9	$27.3	$28.8	$30.4
Energy-Related Expenses	$49.9	$65.2	$83.5	$102.6	$125.3
O&M Expenses	$25.8	$28.3	$31.7	$35.6	$39.9
Assistance and Efficiency Programs	$3.0	$3.2	$3.6	$4.0	$4.4
Taxes and Fees	$5.2	$5.6	$6.2	$6.9	$7.7
City Option Revenue Requirement	**$108.4**	**$128.2**	**$152.4**	**$177.9**	**$207.8**
Estimated Annual Benefit/(Cost) to City	$0.8	($4.4)	($4.5)	($21.7)	($22.7)
NPV of Benefit/(Cost) Over Initial 20 Years	**($137.5)**				

8.3 SENSITIVITY ANALYSES

In addition to the High Cost and Low Cost scenarios that reflect changes to all the identified assumptions on combined basis, sensitivity cases are also conducted to gauge the effect of changing individual assumptions.

Figure 26 compares the Base Case results of the feasibility analysis to the effect of changing each of the identified assumptions. Figure 26 also shows the results of the High and Low Cost Scenarios, which reflect the cumulative effect of the changes for all of the identified assumptions. As shown in Figure 26, when changes in individual assumptions are made to the Base Case, the results vary up or down from the Base Case by approximately $20 to $120 million depending on the assumption changed. However, as described, even when all of the assumptions are changed in the Low Cost Scenario, there is projected to be a significant cost to the City Option on a net present value basis.

Figure 26: Total Changes from Base Case (20-year NPV)



9 ADDITIONAL CONSIDERATIONS

In addition to the potential future economic benefits or costs of operating a municipal electric utility, there are a number of additional factors and risks that a community should consider before deciding to take ownership of an electric distribution system. These include the ability to own, operate and manage a municipal utility and provide adequate oversight and supervision, potential impacts on reliability and the quality of service, the ability to take advantage of technological advancements, the ability to execute on clean energy and other societal goals, and the ability to attract customers. While these issues are not specifically reflected in the economics of the feasibility analysis, these issues may affect the cost structure of a new municipal utility in the City and the service quality received by its customers, therefore these issues are important to be considered prior to forming a new municipal electric utility.

Issues to Consider in Forming a Municipal Electric Utility

- ✓ Capability to execute
- ✓ Risk sharing
- ✓ Governance/oversight
- ✓ Value of Going Concern
- ✓ Power acquisition
- ✓ Municipal utility service offerings and cost impacts
- ✓ Ensuring reliability
- ✓ Lengthy municipalization process

9.1 CAPABILITY TO EXECUTE

The citizens of Pueblo will want to make a realistic assessment of the ability of a City-owned utility to execute on its obligations to provide safe and reliable electric service at levels that approximate or exceed the level of service currently provided by BHE. Electric service is a critical service for the welfare and livelihood of the members of the community, and it is essential that the City be able to own and operate the electric distribution system on a comparable basis to BHE. This includes the ability to effectively manage the day-to-day operations of the utility, addressing and managing cyber security, efficient response to outages and emergencies, and the ability to plan for and successfully implement required future system investments and services.

9.2 SHARING OF RISK

As an investor owned utility subject to the regulatory oversight of the CPUC, the risks of owning and operating an electric utility are currently shared between BHE's customers and its shareholders. To the extent that costs sought for recovery are not approved by the CPUC, or that market conditions result in costs not being fully recovered, those risks are borne by BHE's shareholders. However, under the City Option, those same risks would be borne entirely by Pueblo's municipal utility customers such that rates would need to be increased to fully recover costs incurred by the municipal utility.

9.3 GOVERNANCE/OVERSIGHT

BHE is regulated by the CPUC, and this oversight takes several forms. First, oversight includes a review of every major investment decision by BHE and approval of the terms under which new services can be offered, including the price. Second, the CPUC oversees service quality issues, including the resolution of customer complaints. The CPUC reviews supply and distribution planning activities to ensure that they support the provision of safe, reliable and affordable service as well as other public policy objectives. These functions recognize that electricity is an essential public service that enables the well-being of citizens, the ability of local businesses to thrive and grow, and the achievement of environmental objectives. The CPUC has considerable regulatory authority over BHE, subject to legal restrictions that require BHE be allowed a reasonable opportunity to earn a fair return on invested capital. The CPUC can prevent BHE from earning both a return on and return of any investment that the CPUC deems to have been imprudently incurred.

The public interest requires that the City also establish a governance framework to perform the functions that are currently provided by the CPUC if it were to municipalize (i.e., to oversee the municipal electric utility's reliability, safety and affordability of service, as well as a process for resolving customer billing and other inquiries). This could be achieved in various ways and may include an "electric board" that is either elected or appointed that reviews all major decisions and approves any changes in the prices to be charged. While local authority has advantages, it should be weighed against potential organizational and competency challenges of overseeing a relatively complex industry. In particular, overseeing quality of service requires the ability to assess the trade-off between desired improvements in the quality of service and the costs of achieving such improvements. This may require periodic retention of outside engineering and financial expertise to perform these oversight functions.

9.4 THE VALUE OF THE GOING CONCERN

Going concern represents the incremental value attributable to the fact that the distribution assets that are the subject of a condemnation are not just a collection of physical assets, but together comprise a business unit that is complete, functional, and can be run as a business unit on day one of the acquisition. This value is derived from all the elements that contribute to the complete operating business segment, including the establishment of a customer base, records, maps, and the time and cost of building the business.

In the Preliminary Feasibility Study, there is ***no*** value assigned to the Going Concern as part of the comparison of the City Option and BHE Option. However, to the extent that a determination is made that the City would be required to compensate BHE for the value of the going concern, the additional cost could be a significant incremental cost to the City that is not reflected in the financial calculations of the City

Option herein. For example, Xcel Energy has indicated that the value of the going concern could add $300 million or more to the acquisition value if the City of Boulder forms its own municipal utility.[56]

9.5 POWER ACQUISITION CONSIDERATIONS

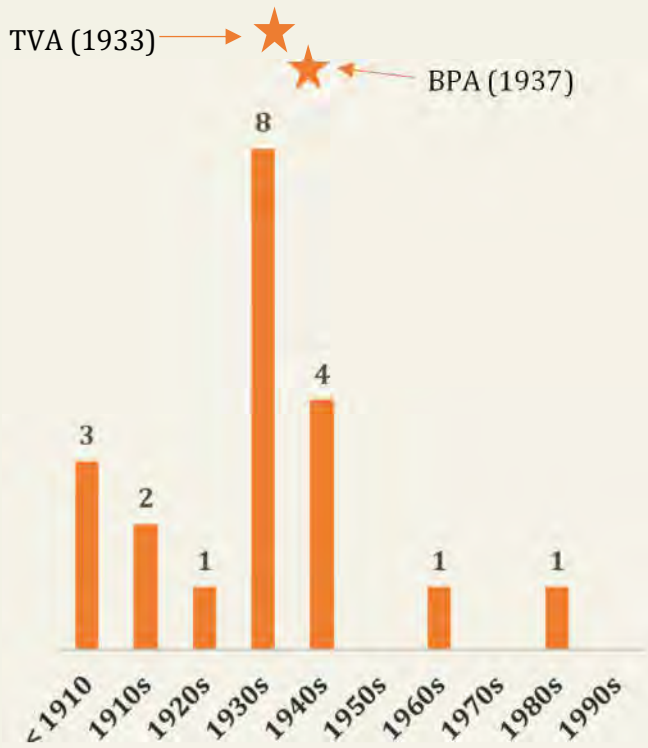
Proponents of municipalization seeking rate reductions often cite large municipal utilities as the solution; however, many of these large municipal utilities were established decades ago to electrify communities and also benefit from federally-funded hydropower or other generating resources. For example, nearly all of the more than 900 cooperatives and 2,200 municipal electric systems were formed in the early 1900s, and rarely through an acquisition approach.

Figure 27: Largest Public Power Utilities

20 Largest Public Power Utilities

- Salt River Project, AZ (1937)
- LADWP, CA (1916)
- CPS Energy, TX (1942)
- NYPA, NY (1931)
- LIPA, NY (1985)
- Memphis Light, TN (1939)
- Austin Energy, TX (1895)
- JEA, FL (1968)
- Nashville, TN (1939)
- Sacramento PUD, CA (1946)
- Omaha PPD, NE (1946)
- Seattle City Light, WA (1904)
- Santee Cooper, SC (1934)
- Snohomish PUD (1949)
- Orlando Utilities, FL (1923)
- City of Chattanooga, TN (1935)
- City of Knoxville, TN (1939)
- Huntsville Utilities, AL (1940)
- Cowlitz PUD, WA (1936)
- Tacoma, WA (1903)

Establishment Year of Largest 20



[56] *See, e.g.*, Dodge, Jefferson and Dyer, Joel, "Boulder's municipalization minefield," Boulder Weekly, February 28, 2013 ("Xcel officials estimate that the city will owe them $300 million in going concern costs…"); Energize Weekly, "Boulder's effort to create a municipal utility faces challenges at the ballot box and in the courts," October 25, 2017; UtiliPoint International, Inc., Boulder Feasibility Analysis, July 11, 2011 (indicating a possible going concern value of $350 million).

Specifically, the average establishment date for the 20 largest municipal utilities is 1934, or 85 years ago. The cost structure that is incurred through the organic growth of a municipality from 1934 to the present is likely to be significantly different than the cost structure that results when a municipality must acquire assets from an investor-owned utility through condemnation and incur significant additional startup costs. In addition, several of the largest public power utilities also benefited from low cost, federally-funded hydropower. For example, of the largest 20 municipal utilities in the U.S., nine are located near the Bonneville Power Administration in the Pacific Northwest or the Tennessee Valley Authority in the Southeast.[57] Access to these federally-funded generation facilities provides these municipal utilities with power rates that are well below current market rates.[58] A municipal electric utility in Pueblo would not likely have consistent access to low cost power from such federal resources.

Another important consideration is the reliability of the power being contracted over the long-term and whether the municipal utility could be subject to future unexpected deliverability problems and/or cost increases if its contractual arrangements are not backed by sufficient generation capacity. As discussed previously, investor-owned utilities undertake extensive planning processes to ensure that their generation portfolios are sufficient to meet their customers' demand requirements throughout the year, including a reserve margin. In other words, the investor-owned utility needs to ensure that it has the ability to serve customers in the event of load variations from what is forecast and extended power plant outages and other unforeseen events that may render generating facilities inoperable or producing a lower amount of electricity for a period of time. To the extent that a municipality purchases power from a third-party provider instead of owning its own generating resources, the municipality needs to ensure that the power that it is purchasing is backed by sufficient capacity and will not be subject to such unforeseen events that may result in reliability concerns. In addition, the municipality needs to ensure that the power it is purchasing will also not be subject to unexpected and significant increases in costs during periods of high electric utilization and/or if generating resources are not capable of producing at their full output.

9.6 MUNICIPAL UTILITY SERVICE OFFERINGS AND POTENTIAL COST IMPACTS

It is important for the City to carefully evaluate the impact of each service that is currently being provided by BHE to determine whether—and on what terms—the service would be provided by the City. BHE currently offers numerous services (e.g., residential services; commercial and industrial services (with variation by size, type of customer, and commitment to serve); area, street, highway, and signal lighting services; and several ratemaking adjustments that are associated with services such as cogeneration and small power production, low-income, energy conservation, and distributed energy production. Not only what services are offered, but the terms of those services, are also important since the terms can affect cost recovery and the rates applicable to customers.

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[57] Includes Seattle City Light, Snohomish County PUD No. 1, PUD No. 1 of Cowlitz County, and Tacoma Public Utilities in the Pacific Northwest and Memphis Light, Gas and Water Division, Nashville Electric Service, the City of Chattanooga, the City of Knoxville, and Huntsville Utilities in the Southeast.

[58] While this report does not specifically address reliability, there is no evidence that Concentric is aware of that suggests that the reliability of public power authorities is stronger than the reliability provided by investor-owned utilities.

Most utilities offer services that are more than "basic" service, and it is important to consider the breadth of the services that would be offered by the municipal utility. These additional services, such as the presence of private solar panels on rooftops, may be provided to all customers, offered to all customers as an option, or offered to a subset of customers based on specified criteria. It is necessary to consider these harder-to-quantify factors to present a valid apples-to-apples comparison between the municipal and utility ownership alternatives. There may be aspects of the existing utility service that a municipality may decide to expand, reduce or abandon, including public benefits programs and value-added services provided by the utility, such as:

- conservation and energy efficiency programs (*e.g.*, in-home audits; insulation installation and appliance rebates);
- low-income assistance;
- financial support for solar energy located on the customer's premises but connected to the utility distribution grid; and
- net metering, which provides customers with compensation for the on-site generation of power that is transmitted back to the distribution system.

The effect of the various services that a municipal utility may offer as compared to the investor-owned utility are an important consideration. For example, an investor-owned utility generally recovers the costs of its services over a large customer base; however, if a municipality were to operate an electric utility and a greater proportion of its customers participate in energy efficiency programs or move to net metering (through installation of private rooftop solar panels), the municipal utility costs may need to be recovered over a smaller electrical sales volume, thereby increasing electricity rates for the remainder of the municipality's customers.

For example, BHE currently provides net energy metering rates for customers with on-site solar generation that produce more electricity than they consume during a billing period. BHE currently compensates customers at the applicable retail rate for such energy production. Accordingly, this net metering policy shifts the responsibility for recovering fixed costs of providing delivery service from the solar customer to all other customers, which is a controversial cost allocation and recovery structure in many states. To the extent that a higher proportion of customers take advantage of BHE's net energy metering tariff in Pueblo relative to other parts of BHE's service area, this could place upward pressure on electricity rates in Pueblo relative to BHE's existing rates unless the City decides to reduce the level of compensation for solar customers. If it were to municipalize, the City would need to establish an approach for offering net energy metering and determine how to compensate its solar customers.

Therefore, the comparison between a municipal-owned utility and continuation of service from the investor-owned utility needs to take such risks into account to provide a fair comparison of the cost of service under each model.

9.7 ENSURING RELIABILITY

The electric industry is currently undergoing a transformation to modernize the electric grid (referred to as "grid modernization"), which is being driven in part by a goal to interconnect solar energy and other distributed resources to the network. The industry is also making advances in information and communications technologies necessary to operate and maintain the distribution network through the increasing penetration rates of these distributed resources. Many utilities are also implementing smart meters and associated systems in efforts to improve the efficiency of the network and provide opportunities for customers to save on their energy bills by changing usage patterns. There are substantial economies of scale associated with the information and other systems required to support distributed resources and smart meters, and these economies should be considered by the electric customers of Pueblo as part of their decision-making regarding the City Option.

Reliability Concerns in Boulder, Colorado

After Boulder initiated its municipalization, several parties expressed concerns, many of which cite reliability as a key concern. These included large-scale electricity consumers such as IBM and the University of Colorado, other large industrial customers, a generation and transmission association, and several consumer groups. The City has finalized agreements with some intervenors, including the University of Colorado; however, significant opposition remains. For example, IBM, along with Xcel Energy, filed a motion in 2017 asking the CPUC to dismiss the City's municipalization application. While the CPUC denied IBM's request to exclude its Boulder campus from the municipal utility's service territory, it agreed the company could raise its concerns at a later date. More recently, IBM filed motions asking for more information on the City's plans. IBM continues to appear reluctant to receiving municipal service but has expressed openness to a five-year trial if the municipalization effort succeeds, although it may relocate its campus if service is subpar.

Sources:
https://www.publicpower.org/periodical/article/boulder-city-council-votes-proceed-with-municipalization
https://www.bizjournals.com/denver/news/2017/08/31/puc-offers-path-forward-for-boulder-xcel-divorce.html
https://bldrfly.com/features/boulders-municipalization-effort-explained/

Grid Modernization

The U.S. Department of Energy established a Grid Modernization Initiative, with a large number of investor-owned utilities around the country focused on implementing grid modernization efforts.

Grid modernization efforts include:

- Improvements in **grid resiliency** and **reliability** in the face of growing climate change and other concerns.
- **Security**, including cybersecurity, to continually address new threats.
- **Flexibility** to create a more agile grid that can utilize a range of resources in meeting grid energy needs.
- **Affordability** to ensure customers benefit from technological gains but are not burdened with significant rate increases.
- **Sustainability** through integration of renewables into grid operations, including reliance on renewables to meet load needs.

Investor-owned utilities around the country are focused on implementing a range of initiatives to address grid modernization issues, including:

- New **software** to automate processes, monitor and control renewable resources to optimize use of renewables.
- Test and roll out new **technologies** for grid reliability, security, and flexibility.
- Integrate **renewables** into grid operations, including electric vehicles, battery storage, smart meters/smart inverters, and large-scale renewables.

Grid modernization efforts require significant funds and a long-term commitment to technological and process improvements that municipal utilities are not equipped to address.

9.8 LENGTHY MUNICIPALIZATION PROCESS

As discussed, municipalization efforts can take many years, sometimes over a decade. The duration of the municipalization effort can drive up costs, both in terms of legal costs to move through the condemnation proceedings, as well as consulting and engineering costs to develop more detailed estimates of the acquisition-related costs. In the case of Pueblo, more detailed engineering studies

will be required regarding such issues as the value of land and easements, stranded assets, and separation and reintegration costs. In addition, given the potential lengthy nature of the municipalization process, the electric market can change dramatically, including the costs of purchasing power.

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