IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A COMMISSION DECISION (1) APPROVING ITS STEAM RESOURCE PLAN, (2) CONDITIONALLY GRANTING IT A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT ONE OF TWO NEW BOILER PROJECTS COMMENCING IN 2016, AND (3) GRANTING SUCH OTHER AND FURTHER AUTHORIZATIONS AND WAIVERS AS THE COMMISSION MAY DEEM NECESSARY

PROCEEDING NO. 14A- ____ST

DIRECT TESTIMONY AND ATTACHMENTS OF SCOTT B. BROCKETT

NOTICE OF CONFIDENTIALITY
A PORTION OF THIS DOCUMENT HAS BEEN FILED UNDER SEAL

Confidential: Attachment No. SBB-4A

December 18, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A COMMISSION DECISION (1) APPROVING ITS STEAM RESOURCE PLAN, (2) CONDITIONALLY GRANTING IT A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT ONE OF TWO NEW BOILER PROJECTS COMMENCING IN 2016, AND (3) GRANTING SUCH OTHER AND FURTHER AUTHORIZATIONS AND WAIVERS AS THE COMMISSION MAY DEEM NECESSARY	)	**PROCEEDING NO. 14A-_____ST**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF SCOTT B. BROCKETT</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

December 18, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A COMMISSION DECISION (1) APPROVING ITS STEAM RESOURCE PLAN, (2) CONDITIONALLY GRANTING IT A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT ONE OF TWO NEW BOILER PROJECTS COMMENCING IN 2016, AND (3) GRANTING SUCH OTHER AND FURTHER AUTHORIZATIONS AND WAIVERS AS THE COMMISSION MAY DEEM NECESSARY	)	**PROCEEDING NO. 14A-_____ST**

SUMMARY OF THE DIRECT TESTIMONY OF SCOTT B. BROCKETT

Mr. Scott B. Brockett is the Director, Regulatory Administration and Compliance, for Public Service Company of Colorado ("Public Service" or "Company"). In this position he is responsible for preparing regulatory, economic and financial analyses in support of regulatory filings and explaining and defending the positions of Xcel Energy in regulatory proceedings.

In his Direct Testimony, Mr. Brockett provides the policy and financial support for the Company's proposed Steam Resource Plan. He first introduces the three other witnesses providing Direct Testimony in this proceeding. He then provides the regulatory and business background and context for the Company's proposed Steam Resource Plan, and identifies where in the Application or testimony the Company addresses the specific requirements from Commission Decision No. C13-1549 in Proceeding No. 12A-1264ST and applicable to this filing.

Mr. Brockett explains that the Company's long-term goal for the steam business is to continue providing reliable and cost-effective steam service over the long term with no contributions from natural-gas or electric customers. To realize this goal the Company requests approval for both an interim (or short-term) plan and a long-term plan. The interim and long-term plans together comprise the Steam Resource Plan for which the Company seeks approval in this proceeding.

Under the short-term plan the Company would upgrade the Zuni plant to allow it to remain operational for steam production purposes until its optimal long-term replacement can be identified and installed. The Company would also upgrade the distribution system around the State Steam Plant to enhance operational flexibility and increase our peak sendout capability by about 40 Mlb. The upgrade to the State Steam plant would be a long-term investment that can be completed quickly. Thus, it would be a component of both our interim and long-term plans.

Under the long-term plan the Company would pursue one of three options: (1) no replacement of the Zuni plant; (2) the replacement of the Zuni plant with one new boiler; or (3) the replacement of the Zuni plant with two new boilers. In addition to approval of our Steam Resource Plan, the Company requests that the Commission grant a conditional CPCN in this proceeding authorizing construction of the one-boiler or two-boiler options, with the final CPCN authorization being deferred until we can better assess our customers' long-term needs. Specifically, during the next 18 months the Company would evaluate expected customer peak loads over the long term and investigate how we could use various demand-side tools to help shape this load. The evaluation of customer peak loads would capture customer responses to the new three-part rate schedule to be implemented on January 1, 2015. The demand-side tools include long-term contracts, rate caps and discounts, and energy-efficiency improvements.

Based on this assessment the Company would submit a filing by July 1, 2016, indicating which one of the three supply-side options applies. Our proposed option would be based on our assessment of the maximum production sendout we need to reliably serve customers' needs. This maximum production sendout, in turn, would be based largely on customer actions through the 2015-2016 heating season. Given that any of the three options selected would have been already approved on a contingent basis, the Company would request expedited consideration and approval of its proposal. This grant of the requested conditional CPCN would allow the Company to install any new boilers required under the selected long-term plan by the beginning of the 2018-2019 heating season and retire the Zuni plant from steam service shortly afterwards.

Mr. Brockett then provides the Company's analysis of the likely revenue requirements and all-in usage rates under the three, alternative long-term plans. The Company incorporates into this analysis a study of the impact of higher steam rates on customer migration, and tests the results of this financial modeling against the results of a survey of steam customers conducted earlier this year.

Mr. Brockett next summarizes the benefits of the proposed resource plan to steam customers – notably stable rates for many years after the long-term plan is implemented and more reliable and efficient service. Mr. Brockett also cites the benefits to the community as a whole – including the freeing up of all or part of the Zuni site for redevelopment.

Based on this assessment, the Company would submit a compliance filing on or before July 1, 2016, setting forth its Required Maximum Production Sendout and which of the three options results from this requirement. Upon final approval, the Company will have authorization to commence construction of any required boiler.

Finally, Mr. Brockett summarizes the approvals requested in this proceeding and the key regulatory and project milestones.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A COMMISSION DECISION (1) APPROVING ITS STEAM RESOURCE PLAN, (2) CONDITIONALLY GRANTING IT A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT ONE OF TWO NEW BOILER PROJECTS COMMENCING IN 2016, AND (3) GRANTING SUCH OTHER AND FURTHER AUTHORIZATIONS AND WAIVERS AS THE COMMISSION MAY DEEM NECESSARY	)	**PROCEEDING NO. 14A-_____ST**

DIRECT TESTIMONY AND ATTACHMENTS OF SCOTT B. BROCKETT

INDEX

SECTION **PAGE**

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
CHP	Combined heat and power
CPCN	Certificate of Public Convenience and Necessity
DSM	Demand Side Management
GRSA	General Rate Schedule Adjustment
IDEA	International District Energy Association
Mlb(s)	Unit of Measurement for Steam Energy. One pound of saturated steam contains 1,000 Btus of heat energy. One Mlb of steam = 1,000 lbs/steam. Therefore one Mlb of steam = 1,000,000 Btus of heat energy
MYP	Multi Year Plan
O&M	Operations and Maintenance
Public Service or Company	Public Service Company of Colorado
Phase II Settlement	Settlement Agreement in Proceeding No. 14AL-0710ST
SCA	Steam Cost Adjustment
S&F	Service and Facility
SVSC	Sun Valley Steam Center
XES	Xcel Energy Services, Inc.

LIST OF ATTACHMENTS

Attachment No. SSB-1	Current Steam Service Territory Map
Attachment No. SBB-2	Index of Compliance with Commission Decision No. C13-1549 in Proceeding 12A-1264ST
Attachment No. SBB-3	Revenue Requirement and All-In Rates
Attachment No. SBB-4	Customer Migration Model 3
CONFIDENTIAL Attachment No. SBB-4A	CONFIDENTIAL Customer Migration Model 3
SBB-5	Customer Migration Model Results
SBB-6	Customer Paybacks
SBB-7	Roadmap

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A COMMISSION DECISION (1) APPROVING ITS STEAM RESOURCE PLAN, (2) CONDITIONALLY GRANTING IT A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT ONE OF TWO NEW BOILER PROJECTS COMMENCING IN 2016, AND (3) GRANTING SUCH OTHER AND FURTHER AUTHORIZATIONS AND WAIVERS AS THE COMMISSION MAY DEEM NECESSARY	)	**PROCEEDING NO. 14A-_____ST**

DIRECT TESTIMONY AND ATTACHMENTS OF SCOTT B. BROCKETT

I. INTRODUCTION, QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Scott B. Brockett. My business address is 1800 Larimer Street, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Xcel Energy Services Inc. ("XES"), the service company affiliate of Public Service Company of Colorado ("Public Service" or "Company"). My title is Director, Regulatory Administration and Compliance.

Q. WHOM ARE YOU REPRESENTING IN THIS PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND DUTIES?

A. I am responsible for preparing regulatory, economic and financial analyses in support of regulatory filings and explaining and supporting the positions of Xcel Energy in regulatory proceedings. I devote almost all of my time to issues involving Public Service.

Q. HAVE YOU INCLUDED A DESCRIPTION OF YOUR QUALIFICATIONS, DUTIES AND RESPONSIBILITIES?

A. Yes. A description of my qualifications, duties and responsibilities is included as Attachment A.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The primary purpose of my testimony is to introduce and provide the policy basis for the Company's plan to address the future of its steam business, which we are referring to in this Application as the "Steam Resource Plan."

First, I introduce the other Company witnesses providing Direct Testimony in support of the Application filed in this proceeding.

Second, I provide the background for this filing, as well as a roadmap identifying where in the Company's Direct Testimony and Application we have addressed the issues specifically identified by the Commission in Decision No. C13-1549 in Proceeding No. 12A-1264ST and applicable to this filing.

Third, I discuss the Company's vision for the steam business and the value of this business to our customers.

Fourth, I explain how the Company has narrowed the number of potential supply-side options and the Company's plans for determining which of these options can best ensure reliable and cost-effective steam service over the long term. I will also discuss our interim or short-term plans for ensuring reliable service until the new supply-side resource(s) can be placed in service.

Fifth, I summarize how the Company will assess over the next 18 months our long-term system peak demands, given recently implemented rate changes and the possibility of stabilizing load through demand-side tools such as long-term contracts, rate discounts, rate caps and energy-efficiency initiatives.

Sixth, I provide estimated long-term revenue requirements and rates under each of the potential long-term options. I rely on this analysis to evaluate the potential risks of various planning options in terms of load erosion and how the Company can mitigate these risks to reasonable levels.

Seventh, I explain and support the Company's financial analysis of likely customer conversions to natural-gas service under different supply- and demand-side alternatives.

Eighth, I explain the short- and long-term benefits of this plan to customers.

Ninth, I provide a diagram of the elements of and analyses supporting the proposed Steam Resource Plan, provide a timeline of regulatory and project milestones, and summarize the regulatory approvals the Company requests in this Application.

II. INTRODUCTION OF WITNESSES

Q. PLEASE IDENTIFY THE OTHER COMPANY WITNESSES SPONSORING DIRECT TESTIMONY AND THE PURPOSE OF THEIR TESTIMONY.

A. The other company witnesses are Stephen P. Kutska, Thermal Energy Development Manager, Tim M. Farmer, Manager of Engineering, and Jennifer Wozniak, Manager, Strategic Communications.

Mr. Kutska will address:

- the short-term and long-term operational needs of the steam business,
- how the Company estimates system peak loads for planning purposes,
- how current and potential customers may respond to changes in steam rates due to the recent rate-design changes and the various supply-side options that the Company has identified,
- the basis for the Operations and Maintenance ("O&M") expenses that the Company estimates under the various supply-side options, and
- the Company's collaboration with various stakeholders.

Mr. Farmer will explain how the Company identified and analyzed a wide variety of supply-side options for meeting the Company's immediate and long-term needs. He will then support the two interim measures and three supply-side options the Company is proposing in this proceeding based on this analysis.

Ms. Wozniak will discuss the survey of steam customers that the Company completed in the second quarter of 2014 and the results of that survey.

III. HISTORY AND BACKGROUND

A. History of Steam System

Q. PLEASE PROVIDE A HISTORY OF THE STEAM BUSINESS TO GIVE CONTEXT TO THE COMPANY'S APPLICATION IN THIS PROCEEDING.

A. Public Service has provided steam to downtown Denver customers since 1879. According to the International District Energy Association ("IDEA"), the Company's steam system is the oldest continuously operated commercial steam utility in the world. The Company's district steam system includes three steam boiler stations that supply steam to the downtown steam distribution system -- the Electric Department's Zuni Station ("Zuni"), the Denver Steam Plant, and the State Steam Plant. We deliver the steam produced by these boilers to 129 buildings in downtown Denver through a delivery system of distribution mains, services and supporting equipment. The Company's steam service territory encompasses an area in downtown Denver that extends roughly from Zuni Street to 20th Street and from Wewatta Street to 13th Avenue. The Company's current steam service territory is depicted in the Map included as Attachment No. SBB-1. Mr. Farmer and Mr. Kutska describe the steam business in more detail in their testimonies.

B. Regulatory Background

Q. PLEASE SUMMARIZE THE REGULATORY CONTEXT FOR THE COMPANY'S APPLICATION.

A. On December 12, 2012, Public Service filed Advice Letter No. 119-Steam proposing an increase in base rate revenues, which was subsequently suspended and set for hearing before an administrative law judge ("ALJ") in Proceeding No. 12AL-1269ST. Prior to this filing, steam rates had not been adjusted since the Company's 2005 Phase I rate case in Proceeding No. 05S-369ST. On November 6, 2013, the Commission approved a Settlement among all parties in Proceeding No. 12AL-1269ST allowing a General Rate Schedule Adjustment rider of 27.24 percent to go into effect January 1, 2014. (See Decision No. R13-1388).

On the same date that the Company submitted its request for an increase in base rates, we also filed an Application in Proceeding No. 12A-1264ST seeking a Certificate of Public Convenience and Necessity ("CPCN") to construct a new steam production facility – the Sun Valley Steam Center ("SVSC"). In conjunction with this CPCN request, the Company also requested approval of a regulatory plan whereby the capacity costs of our gas and steam departments would be combined and allocated based on the coincident peak loads of both gas and steam customers.

In Decision No. C13-1549 (Mailed Date: December 18, 2013), the Commission denied our Application without prejudice. In that decision, the Commission also required the Company to file a "needs assessment of the steam system and its plans to meet those needs, consistent with the discussion above" within 180 days. The Commission later granted the Company's request to extend the deadline for submitting this filing to one year from the date of the decision, or December 18, 2014. (See Decision No. C14-0068). I hereafter refer to the needs assessment and the Company's plans for meeting those needs, as specified in this Decision No. C13-1549, as the "Steam Resource Plan."

One reason the Company requested additional time to file the Steam Resource Plan was to allow us to file a Phase II rate case based on the test-year revenue requirement approved in Proceeding No. 12AL-1269ST. We submitted the Phase II filing on June 26, 2014, with Advice Letter No. 124-Steam, which was subsequently suspended and set for hearing before an ALJ in Proceeding No. 14AL-0710ST. The Company proposed new rates that included a fundamental rate-design change. Specifically, the Company proposed to modify the rate structure for all steam customers from a two-part rate consisting of usage and customer charges to a three-part rate consisting of usage, customer and demand charges. The Company proposed to add a demand charge to signal customers that peak loads drive the majority of our base cost of service.

The Company also proposed to update our Steam Cost Adjustment ("SCA") on a quarterly basis rather than annually. The Company proposed more frequent SCA adjustments to prevent large fluctuations in SCA rates caused by large deferred balances.

Finally, in recognition that the three-part rate structure might render steam service uneconomical for customers with low load factors, the Company proposed to maintain the existing two-part rate structure for any customers that notify the Company within 30 days of the effective date of the new rates, of their commitment to leave the steam system by October 1, 2015.

On October 1, 2014, the Company filed a Settlement Agreement ("Phase II Settlement") Proceeding No. 14AL-0710ST comprehensively resolving all issues among the parties. This Phase II Settlement provided for no substantive changes to the Company's proposed rate design, opt-out provision, or the SCA tariff changes. The ALJ issued a Recommended Decision on October 6, 2014, approving the Phase II Settlement without modification. (See Decision No. R14-1217). This Recommended Decision became a decision of the Commission on October 26, 2014. Pursuant to the approved Settlement, the three-part rate structure will be implemented on January 1, 2015, and the first quarterly SCA will be filed in March 2015 for implementation on April 1, 2015.

As I will explain in more detail later in my testimony, the new rate design, opt-out provision, and quarterly SCA will facilitate system planning for the steam business. However, the impacts of the new rate design and opt-out provision on our system peak demand are currently unknown. The Company's proposed schedule for finalizing and executing our long-term strategy is premised substantially on the need to evaluate the impacts of these Phase II changes when better information on future customer load is available.

Q. GIVEN THIS REGULATORY BACKGROUND FOR THE FILING, HOW DOES THE COMPANY VIEW THE STEAM RESOURCE PLAN BEING SUBMITTED IN THIS FILING?

A. The Steam Resource Plan, as the name suggests, is essentially a mini resource plan for the steam utility. It is similar to, but on a much smaller scale than, an electric resource plan. While in Decision No. C13-1549, the Commission has directed us to conduct some specific analyses in Decision No. C13-1549, the Commission also expects us to supplement these analyses in order to develop a complete needs assessment and plan to address those needs. In other words, the instant filing must address not only the specific compliance items identified in Decision No. C13-1549, but also the other elements of a comprehensive plan.

Q. DO YOU WISH TO HIGHLIGHT ANY UNIQUE CHALLENGES ASSOCIATED WITH THE STEAM RESOURCE PLAN THE COMPANY WAS DIRECTED TO PREPARE?

A. Yes. There are many challenges, but I wish to highlight one in particular: the long-term forecasting of customer loads. While long-term demand forecasts are always an issue in electric resource planning, the forecast uncertainty is generally much less on a percentage basis than it is for the steam business in its current environment. The reason is that the assumed impacts of projected rate changes on electric customer loads are relatively modest (the price elasticity of demand for electric service is assumed to be relatively inelastic). In contrast, the magnitude of both known and potential long-term steam rate changes and the availability of alternatives to steam service could result in significant load changes. As explored in considerable detail in Proceeding No. 12A-1264ST, steam customers have the option of self-generating steam through the installation of on-site boilers, which would allow them to discontinue the

Company's steam service. While the Company believes we can manage this uncertainty, it does present a unique challenge.

While this focus on load uncertainty is not intended to minimize supply-side challenges, the assessment of supply-side options for the steam business is more straightforward.

Q. HAS PUBLIC SERVICE COMPLIED WITH THE SPECIFIC FILING REQUIREMENTS THAT THE COMMISSION SPECIFIED IN DECISION NO. 13-1549?

A. Yes. Attachment No. SBB-2 identifies where in the Company's Direct Testimony and Application we address each filing requirement.

IV. OVERVIEW OF COMPANY'S STEAM RESOURCE PLAN AND REQUESTS

Q. WHAT IS THE COMPANY'S LONG-TERM VISION FOR THE STEAM BUSINESS?

A. Public Service has offered steam service for over 100 years. We believe that most customers place a high value on this service and will remain on the system if rates can be managed to reasonable and stable levels. Consequently, Public Service's goal is to offer reliable and economic steam service on an ongoing and permanent basis. Moreover, we want the steam service to pay its own freight. We are not seeking contributions from the Company's gas or electric customers or considering a graceful exit strategy. We believe that we have the necessary tools to plan and manage the business as a long-term enterprise. In fact, we believe our long-term plan will ensure a more efficient system and a more efficient level and pattern of customer use.

Q. DOES THAT MEAN THE COMPANY IS NOT PROPOSING AN EXIT STRATEGY AS PART OF ITS STEAM PLAN?

A. Yes. An exit strategy would be required only if we failed in carrying out our mission for the business. We recognize that – regardless of our vision of the future -- customers are free to leave the steam system if they identify more attractive energy alternatives. But the Company has no intention of planning for or facilitating a systematic conversion to natural gas or some other energy source. Moreover, if the Company's plans were thwarted by a vicious cycle of load losses, price increases caused by the load losses, and further load losses caused by the price increases, the Company would consider temporary rate caps and other options to stem the exodus before resorting to an exit strategy.

Even if an exit strategy were required, any exit strategy would need to be tailored to the specific circumstances necessitating such a strategy. At this point the circumstances that would drive such an exit strategy are unknown. If circumstances change over the next 18 months such that an exit strategy were required for some reason, we would incorporate such a strategy into our July 1, 2016, filing that I discuss later in my testimony.

Q. WHY DOES THE COMPANY BELIEVE DISTRICT STREAM SERVICE PROVIDES HIGH VALUE TO CUSTOMERS?

A. The Company's steam service provides a variety of advantages. For example, steam service provides customers with the option of not installing boilers and related equipment to serve their space-heating or process needs. This advantage is very important to downtown customers who value architectural flexibility, have limited space, and/or have limited capital budgets. Moreover, steam service relieves customers of the responsibility of maintaining boilers and incurring ongoing management costs -- such as hiring specialized staff or arranging for the delivery and transportation of gas commodity. Steam service also is a very reliable and clean energy resource.

Through steam service downtown customers are able to reduce the burden of procuring energy services and are better able to focus on their primary business objectives.

Q. DOES THE COMPANY HAVE ANY INDICATION OF HOW CUSTOMERS RANK THESE ADVANTAGES?

A. Yes. As Ms. Wozniak explains in more detail, the Company commissioned a survey of our steam customers earlier this year. One survey question asked respondents to rank by level of importance a variety of reasons for why they decided to use the Company's district steam system. The respondent rankings, from most important to least important, are listed below:

1. Use of existing infrastructure (*i.e.,* too costly to convert to new system, facility space requirements, etc.);
2. Reliability of being connected to the city / district heating system (*i.e*., no unscheduled outages);
3. Dependability / Reliability of steam exchangers (*i.e*., long life and low maintenance costs, etc.);
4. Clean energy (*i.e*., no potentially hazardous gases, etc.);
5. Little or no ongoing maintenance costs (*i.e.,* specialized staff required, etc.); and,
6. Workplace comfort of steam energy.

Q. DO YOU HAVE ANY OTHER INDICATION FROM CUSTOMERS OF THE VALUE THEY PLACE ON STEAM SERVICE?

A. Yes. Some of the other key survey results related to the value of steam service are summarized below:

- About 75 percent of respondents are very satisfied with the overall quality of the Company's steam service.
- Over three-fourths (78 percent) of steam customers are satisfied with the overall package of projects and services purchased from the Company.
- Over one-half of the respondents (52 percent) indicated that they value steam system service. Open feedback from steam customers suggested that satisfaction and value could be increased by offering lower steam rates and maintenance costs, new infrastructure and added services.
- About 60 percent of respondents believe that having the choice to use the Company's steam service is very important.
- About 48 percent of respondents prefer that the Company run the steam system. Only 17 percent would prefer to run the system independently, while 35 percent do not know.

Q. WHAT ARE THE PRIMARY CHALLENGES TO DEVELOPING A PLAN TO REALIZE THE VISION FOR STEAM SERVICE?

A. Any sound plan must address several fundamental questions and uncertainties. First, for any given level of system peak demand, what supply-side side resources should the Company deploy? Second, for which of these potential levels of system peak demand should the Company plan, given that the

Company can help shape this peak demand? Third, how can the Company ensure reliable service over the next several years, before the new supply resources can be placed in service?

The Company has approached these challenges systematically. We have determined that while there are many potential levels of system peak demand, there are only three optimal supply-side options for meeting these system peak demands reliably and economically over the long term. Moreover, regardless of the level of system peak demand for which we plan, the Company must also take additional steps to ensure reliable service until such time as the long-term plan can be implemented.

V. SUPPLY-SIDE OPTIONS

Q. HOW DID THE COMPANY EVALUATE POTENTIAL SUPPLY-SIDE OPTIONS AND DECIDE WHICH OPTIONS TO PROPOSE?

A. The fundamental issue facing the Company is how to replace the aging Zuni plant, which can currently provide about 45 percent of our total steam capacity. In Decision No. C13-1549, the Commission clearly directed the Company to address more thoroughly all reasonable supply-side options. In response, the Company first identified the population of potentially viable replacement options. These options include new boilers on or around the Zuni site, new boilers at another location, new or upgraded boilers at existing customer sites, and combined heat and power ("CHP") plants.

As explained by Mr. Farmer, the Company identified 15 options for evaluation based on their costs and contributions to system reliability. Based on this evaluation the Company proposes three long-term supply-side options: no replacement for Zuni (the "No New Boiler Option"), replacement of Zuni with one new boiler (the "One New Boiler Option"), and replacement of Zuni with two new boilers (the "Two New Boilers Option"). Moreover, under each of these scenarios the Company proposes to upgrade the State Steam Plant to add 40 Mlb of additional peak capacity and improve our operational flexibility. While this upgrade will provide long-term value to customers for over the next 30 years, it can also be completed quickly and is warranted regardless of the load for which the Company ultimately plans. Consequently, the Company proposes this upgrade as a component of both our short-term (interim) and long-term plans.

Under either of the two long-term plans that entail new boilers, the Company must take steps to ensure reliable service until the new boilers can be installed. As I will explain in more detail later in my testimony, the Company estimates an in-service date for either of the new boiler options in October 2018. Between now and October 2018 the Company plans two initiatives to ensure system reliability. First, as explained above, the Company proposes to upgrade the State Steam Plant. This upgrade should be completed by November 2016. Second, as Mr. Kutska and Mr. Farmer explain in their testimony, the Company proposes additional investments and maintenance for the Zuni plant to help extend its useful life until at least October 2018. The capital upgrades at Zuni would be completed by the end of October 2016. The Company proposes to recover these costs over five years, or through 2021. The additional O&M expenses would be incurred until the Zuni unit was retired from steam service.

Q. WOULD THE TWO INTERIM INITIATIVES BE REQUIRED EVEN IF THE COMPANY ULTIMATELY DECIDES IT DOES NOT NEED TO REPLACE ZUNI WITH A NEW BOILER?

A. Yes. The Company believes the upgrade to the State Steam Plant is warranted regardless of whether any new boilers are required. Under the No New Boiler Option the Company may be able to shut down the Zuni plant sooner. But we assume for purposes of our financial analyses in this proceeding that the timing of the Zuni retirement does not vary among the three long-term options.

Q. UNDER WHAT CONDITIONS WOULD THE COMPANY IMPLEMENT EACH OF THE THREE LONG-TERM OPTIONS?

A. The Company's decision will be based on the system peak load for which we need to plan over the next 20 years. As explained by Mr. Kutska, this targeted peak hourly load is based not on *expected* coincident peak loads during a given heating season, but rather on the expected peak loads assuming extremely cold weather and higher-than-average customer usage. The weather conditions used for system planning are unlikely to occur during any given heating season, but could reasonably be expected to occur at least once over the long-term planning horizon. Moreover, the amount of production capacity for which the Company plans must also account for losses over the delivery system – from the boilers to the customer meter. This means that the amount of stream production capacity we need far exceeds the expected system coincident peak loads measured at customers' premises.

To distinguish the customer coincident peak loads at the meter during a typical year from the customer coincident peak loads at the meter assuming extreme weather conditions and above average customer usage, I will refer to the former as the "Expected System Coincident Peak Load" and to the latter as the "Design Hour System Coincident Peak Load." To distinguish these different measures of peak load at the customer meter from the amount of production capacity we must secure to meet these customer loads (*i.e.,* after adjusting for losses over the distribution system), I will refer to the latter as the "Required Maximum Production Sendout."

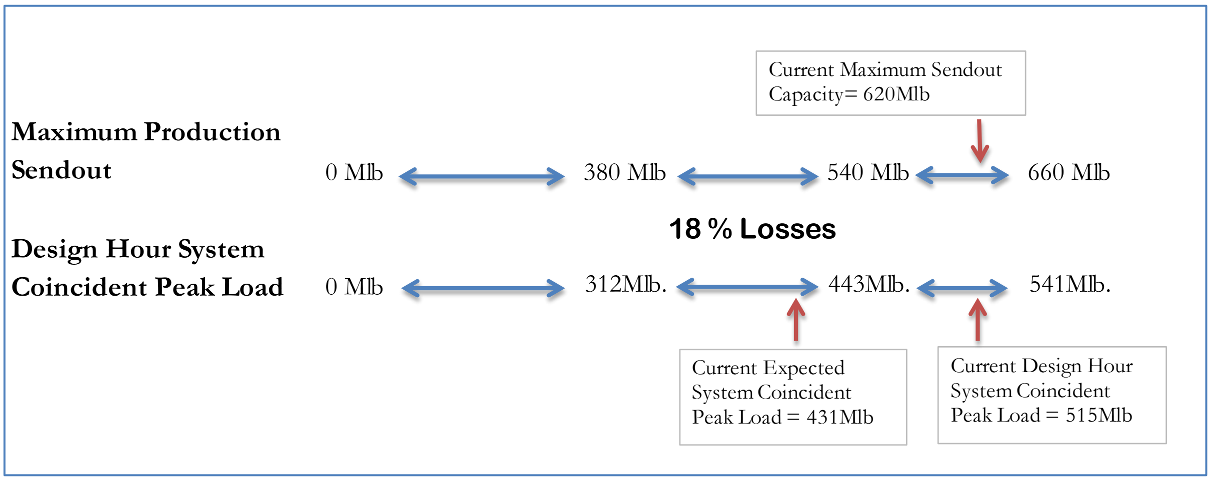
This approach to long-term system planning is analogous to the approach the Company uses to plan the electric and natural-gas systems. We plan our electric bulk-power system to ensure that during any year we have sufficient generation capacity to meet customers' expected coincident peak loads after line losses, plus a planning reserve margin of 16.3 percent to account for unanticipated increase in peak load (due to extreme weather or favorable economic conditions) and/or unit outages. In planning the gas system we impute peak loads under a hypothetical "Design Day" based on extreme weather conditions. The approach explained by Mr. Kutska is the steam analogue to the planning criteria with which the Commission is familiar for electric and gas system planning.

The Company would select the option of not replacing Zuni with any new capacity if we believed our Required Maximum Production Sendout would never exceed 380 Mlb. The One New Boiler Option would be selected if we believed our Required Maximum Production Sendout would fall between 380 Mlb and 540 Mlb. The Two New Boilers Option would be selected if the Required Maximum Production Sendout exceeded 540 Mlb.

To provide some perspective for these thresholds, the current Design Hour System Coincident Peak Load is about 515 Mlb, which translates into a Required Maximum Production Sendout of about 628 Mlb. In other words, the option of not replacing Zuni with any new capacity would be viable only if our Design Hour System Coincident Peak Load permanently declined by at least 40 percent from current levels (from 515 Mlb to 312 Mlb). The option of replacing

Zuni with one boiler would be justified if the Design Hour System Coincident Peak Load declined from about 14 percent to about 39 percent. The option of replacing Zuni with two boilers would be selected if our customer loads increased or remained relatively stable. The table below summarizes the option thresholds:

Table 1 - Required Maximum Production Sendout Ranges



Q. HOW DOES THE COMPANY PLAN TO DETERMINE THE REQUIRED MAXIMUM PRODUCTION SENDOUT IT WILL NEED OVER THE LONG TERM?

A. While the Company has evaluated customer loads over the past several years, we do not have sufficient data at this point to pinpoint a Design Hour System Coincident Peak Load with sufficient confidence. But over the next 18 months the Company plans to conduct an in-depth assessment of customer loads, particularly coincident peak loads. I explain this assessment in the next section of my testimony. Once we estimate the Design Hour System Coincident Peak Load, we can derive a corresponding level of Required Maximum Production Sendout based on the approach that Mr. Kutska outlines.

VI. DETERMINATION OF SYSTEM COINCIDENT PEAK DEMAND AND REQUIRED MAXIMUM PRODUCTION SENDOUT

A. Overview

Q. PLEASE EXPLAIN WHY THE COMPANY CANNOT IDENTIFY CUSTOMER LOADS WITH SUFFICIENT CERTAINTY TO COMMIT TO A LONG-TERM SUPPLY-SIDE PLAN IN THIS PROCEEDING?

A. There are two primary reasons. First, customers have not had sufficient time to respond to recent rate and tariff changes. These changes include the base rate increase implemented on January 1, 2014, the rate-design changes to be implemented on January 1, 2015, and the opt-out provision customers can select on or before January 31, 2015.

Second, the Company need not be totally reactive; we can deploy a variety of demand-side tools to help encourage or retain load when it makes economic sense. Among these tools are long-term contracts, rate discounts, rate caps and energy-efficiency initiatives. While the Company has explored these options on a preliminary basis, we are not yet positioned to represent the likely impact of these tools on our long-term capacity needs.

Moreover, regardless of whether the Company pursues new load, actual and potential load growth must also be considered in long-range planning.

I will discuss the pricing changes, tariff changes and potential demand-side tools in more detail below.

B. Rate And Tariff Changes

Q. WHY IS IT CRITICAL TO GAUGE CUSTOMER REACTION TO RECENT AND IMPENDING RATE AND TARIFF CHANGES BEFORE COMMITTING TO A LONG-TERM MAXIMUM REQUIRED PRODUCTION SENDOUT?

A. The rate changes are significant. Not only did base rates increase by 27.24 percent on January 1, 2014, but the Company will implement rate-design changes on January 1, 2015, that will have large impacts on some customers. The new rate design might convince some customers with high load factors to remain on the system. Other customers with low load factors might decide to exit the system, either by notifying the Company of their intention to leave the system in accordance with the approved opt-out provision or exit later in response to their bills during this heating season or the next heating season.

But customer response to these pricing changes will not be limited to decisions to remain on the system or leave the system. To date customers have never been encouraged through price signals to reduce their loads during critical peak periods. But these signals will commence in January 2015. The Company fully expects that customers who choose to remain on the system will still be financially motivated to reduce their peak demands. Many customers will probably learn from their experience during the current heating season, and more fully adjust their peak loads and usage in response to the new price signals during the heating season of 2015-2016. The Company also recognizes that customers will continue to adjust their usage in future years, particularly to the extent such adjustments require capital expenditures subject to long lead times for approval and implementation. Nonetheless, by the end of the 2015-2016 heating season the Company should have sufficient data on customer responses to commit to a long-term supply-side plan.

Q. DOES THE COMPANY ALSO EXPECT CUTOMERS TO RESPOND TO THE SCA INCREASE FROM $7.862 PER MLB TO $10.376 PER MLB, WHICH WILL BE IMPLEMENTED ON JANUARY 1, 2015?

A. Customer response to this increase is uncertain, but we hope the response is limited. The SCA increase is attributable not to the cost of providing service in 2015, but to under-collections of commodity costs in 2014 (the deferred component of the 2015 SCA). These prior under-collections are scheduled to be fully recovered by the end of 2015, after which time the SCA should decline significantly absent, unexpected increases in the price of natural gas. Consequently, the Company is hoping that customers properly recognize that the 2015 SCA represents a temporary cost increase that should not affect their long-term plans.

Q. BUT WON'T SOME CUSTOMERS BE MOTIVATED TO LEAVE THE SYSTEM TO AVOID FUTURE SCA INCREASES ATTRIBUTABLE TO UNDER-COLLECTIONS?

A. No, they should not be. The large SCA deferred balance at the end of 2014 was generated substantially because the Company typically adjusts its SCA only once per year. As a result, projections of gas prices that turn out to be too low contribute to under-collections over an entire year. However, in the most recent Phase II proceeding the Company received Commission approval to adjust the

SCA on a quarterly basis. The salient advantage of these more frequent adjustments is that they can incorporate changes in gas price forecasts on a more timely basis, thereby mitigating the accumulation of large under-collections. In other words, the probability of large SCA changes due to under-collections of commodity costs will be significantly reduced as a result of the implementation of the quarterly SCA. Consequently, when customers assess the long-term viability of steam service they need no longer worry about large changes to the SCA prompted by previous under-collections.

Q. EVEN IF CUSTOMERS ARE NO LONGER AT RISK FOR SCA INCREASES ATTRIBUTABLE TO PREVIOUS UNDER-COLLECTIONS, AREN'T THEY STILL AT RISK FOR GAS PRICES INCREASES IN GENERAL?

A. Yes. The price of natural gas, as with most commodity prices, can certainly fluctuate from year to year. Steam customers will continue to assume this price risk. But for most customers the only viable option to steam service is natural-gas service, which also entails the risk of increases in gas prices.

C. Long-Term Contracts And Rate Discounts

Q. WHY ARE YOU DISCUSSING LONG-TERM CONTRACTS AND RATE DISCOUNT IN THE SAME SECTION OF YOUR TESTIMONY?

A. Long-term contacts and rate discounts are linked; in return for any rate discount provided to a customer, the Company would probably require a longer-term commitment.

Q. DOES THE COMPANY CURRENTLY OFFER ANY DISCOUNTED RATES WITH THE CONCOMITANT CUSTOMER COMMITMENT TO A LONG-TERM CONTRACT?

A. Yes. The Company currently offers rate discounts under two contracts, each with a term of 25 years.

Q. UNDER WHAT CONDITIONS WOULD THE COMPANY OFFER ADDITIONAL RATE DISCOUNTS?

A. Any rate discounts offered to steam customers must satisfy the statutory requirements itemized in C.R.S. 40-3-104.3. But I would stress three criteria in particular. First, the discounted price must recover our marginal cost of providing service. Second, the discounted price must be no lower than the cost of the customer's competitive alternative. Third, the customer must commit to receiving service for a period long enough to benefit our long-term system planning.

Q. WOULD RATE DISCOUNTS AND LONG-TERM CONTRACTS BE AN INTEGRAL COMPONENT OF THE COMPANY'S STRATEGY FOR FORECASTING SYSTEM PEAK LOADS WITH MORE CERTAINTY?

A. The likely impact of long-term contracts and rate discounts is unknown, but by no means are these tools a panacea for load uncertainty. They would probably – at best – only complement or supplement other planning initiatives.

Q. WHY DO YOU BELIEVE THE POTENTIAL FOR LONG-TERM CONTRACTS AND RATE DISCOUNTS IS LIMITED?

A. I would cite three reasons. First, under current Colorado statues the Company cannot recover rate discounts from other steam customers. Consequently, widespread rate discounts would jeopardize the financial viability of the steam business.

Second, the Company would insist upon a well-developed and verifiable estimate of the cost of a customer's competitive alternative before offering a rate discount. It is unclear how many customers would be in a position to provide this support.

Third, the Company would insist upon a long-term service commitment. Again, it is unclear how many customers would be willing to provide such a commitment.

Q. GIVEN THESE CAVEATS, WILL THE COMPANY CONTINUE TO EVALUATE THE POTENTIAL FOR LONG-TERM CONTRACTS AND RATE DISCOUNTS?

A. Yes. Even in light of these caveats carefully targeted rate discounts could be beneficial. The long-term retention of as few as one or two significant loads could provide planning benefits. Moreover, some survey respondents indicated a willingness to entertain long-term contracts. Specifically, 61 percent of respondents would consider entering into a long-term contract in exchange for a price guarantee. Of the respondents willing to entertain long-term contracts, 79 percent would prefer a contract term of 6-10 years. Consequently, the Company will continue to explore such options with price-sensitive customers and incorporate the results of these efforts into our long-term assessment of the Required Maximum Production Sendout.

Q. IS THE COMPANY CURRENTLY IN A POSITION TO IDENTIFY A SPECIFIC CUSTOMER TO WHICH A LONG-TERM CONTRACT WITH SPECIAL PRICING PROVISIONS WOULD BE OFFERED?

A. No. It is premature at this point to commit to any specific special contracts. Over the next year customers can gain experience with the new rate design, evaluate the potential long-term costs of service based on the information provided in this proceeding, and evaluate the long-term costs of alternative energy services. At that point both the customer and the Company will be in a better position to assess the feasibility of long-term contracts.

Q. ARE THERE ANY PERMUTATIONS TO THE OPTION OF PROVIDING RATE DISCOUNTS IN RETURN FOR LONG-TERM SERVICE COMMITMENTS?

A. Yes. Another way to reduce load uncertainty is to commit to rate caps that do not necessarily result in rate discounts. I discuss rate caps below.

D. Rate Caps

Q. HOW WOULD RATE CAPS BE USED TO HELP STABILIZE LOADS?

A. There are two ways to implement rate caps. The first is on a targeted or customer-specific basis. Instead of offering a rate discount in return for a long-term service commitment, the Company would commit to a base-rate cap. This cap would be above current base rates -- and perhaps above expected future base rates – but would provide a financial hedge or protection against future rate increases. This offering might be attractive to customers who believe steam service is the best long-run option as long as the relationship between rates for steam and natural-gas service remains relatively stable. As with rate discounts, the Company will explore rate caps with customers prior to determining our long-term Required Maximum Production Sendout.

The second way to implement rate caps is on a generic basis. Instead of negotiating rate caps with individual customers in return for their long-term service commitments, the Company would commit to base-rate caps for all customers over a given number of years. This generic approach might be preferable if there were an identifiable "tipping point" for steam rates that would prompt significant load loss.

E. Energy-Efficiency Initiatives

Q. IS THERE SIGNIFICANT POTENTIAL FOR ENERGY-EFFICIENCY IMPROVEMENTS ON CUSTOMER PREMISES?

A. We believe there are some promising possibilities. The most attractive opportunities include improvements to heat exchangers, control valves, control systems and insulation.

Q. IS THE COMPANY REQUESTING THAT THE COMMISSION APPROVE A FORMAL DEMAND SIDE MANAGEMENT PROGRAM FUNDED BY ALL STEAM CUSTOMERS, SIMILAR TO THE COMPANY'S GAS AND ELECTRIC DSM PROGRAMS?

A. Not at this time. While the Company believes a steam DSM program is permissible under Colorado statutes, we are not convinced that a formal program is warranted. We can certainly assist customers with energy-efficiency efforts without providing any funding -- based on our knowledge of various end-use technologies and the research we have conducted on the most promising opportunities. But going beyond this assistance by offering a formal, customer-funded DSM program is a step that should not be undertaken lightly, as a formal program may raise rates to customers unable or disinclined to avail themselves of the Company's offerings.

However, as the Company continues its research and discussions with customers, we may decide to request Commission approval of a formal steam DSM program.

Q. DOES THE COMPANY EXPECT CUSTOMERS TO IMPLEMENT ENERY-EFFCIENCY IMPROVEMENTS ON THEIR OWN IN RESPONSE TO RISING STEAM COSTS?

A. Yes. While customers may focus first on low-cost behavioral changes to reduce their winter peak loads, energy-efficiency efforts can reduce the usage portion of their bills as well as the demand portion. It is important to remember that even after implementation of the strong price signal to customers to manage their peak loads, the majority of a typical customer's bill will still be the usage charge (base usage charge plus SCA). The Company expects customers to explore ways to reduce their annual use as well as their peak demands. In most cases the efficiency improvements undertaken to reduce customers' annual use will also reduce their peak loads. Consequently, the lack of a formal, utility-sponsored DSM program should in no way be interpreted as an expectation of no additional efficiency improvements on customer premises.

F. New Loads

Q. IS THERE ANY POTENTIAL FOR ADDING NEW LOADS TO THE STEAM SYSTEM?

A. Yes. For example, customers with high load factors may conclude that steam is a more attractive alternative under the new rate design. In fact, Mr. Kutska discusses a potential new load in his testimony. While the Company is not seeking to expand its footprint, existing steam customers can benefit from additional load within the current footprint as long as revenues from the load exceed the incremental cost of serving the load. The Company will certainly incorporate any actual or anticipated new loads into its long-term planning.

VII. PROJECTED LONG-TERM RATES UNDER THE THREE SUPPLY-SIDE SCENARIOS AND POTENTIAL IMPACTS ON CUSTOMER LOADS

Q. HAS THE COMPANY DEVELOPED PROJECTED REVENUE REQUIREMENTS AND RATES UNDER EACH OF THE THREE SUPPLY-SIDE OPTIONS?

A. Yes. The Company has estimated base revenue requirements and all-in rates per Mlb for a typical steam customer from 2015 through 2034 under each of the supply-side options discussed above. The derivation of these revenue requirements and rates is included as Attachment No. SBB-3.

I should emphasize that the rates derived in this attachment are based on the assumption of current cost recovery in each year, *i.e.,* rates would be adjusted each year to capture the changes in the cost of service and billing determinants. As explained later in my testimony, the Company hopes to recover its future cost increases in a timely manner. Nonetheless, the assumption of current cost recovery each year represents a "worst-case" scenario in terms of all-in rates.

Q. HOW DID YOU ESTIMATE THE BASE REVENUE REQUIREMENTS UNDERLYING THESE PROJECTIONS?

A. For each year the nominal base revenue requirements are estimated by adding the incremental costs under each of the three options to the base revenue requirement of $10.7 million that the Commission approved in Proceeding No. 12AL-1269ST. In other words, the Company assumes no increase in base revenue requirements from 2015 through 2034 other than the incremental costs of the supply-side options.

The estimated revenue requirements of each supply-side scenario include the costs of both the interim and long-term components of the plan. The interim costs are assumed to be identical under all three options. Specifically, the timing and levels of cost incurrence for the upgrades to the Denver Steam Plant would be identical under each option. Likewise, the Company would shut down Zuni around the end of 2018 -- and avoid any future O&M expenses – under any of the three scenarios.

Q. ARE THE INCREMENTAL REVENUE REQUIREMENTS ASSOCIATED WITH THE ZUNI PLANT LIMITED TO THE COSTS OF THE PLANT UPGRADES?

A. No. The extension of Zuni's life for steam service past 2015 requires that the steam department absorb all of the O&M expenses that the electric and steam departments currently share. This transfer of O&M expenses to the steam department represents another incremental cost of the decision to use the Zuni plant to ensure reliable stem service until more permanent supply-side options can be installed. Under each scenario this cost transfer shows up as an incremental revenue requirement (O&M expense) from January 2016 through the date on which Zuni is retired from steam service.

Q. DO YOU BELIEVE THE ASSUMPTION OF NO ADDITIONAL BASE COST INCREASES OVER THE PLANNING PERIOD – OTHER THAN THE INCREMENTAL COSTS OF THE INTERIM AND LONG-TERM OPTIONS -- IS REASONABLE?

A. Yes. The base cost of service comprises primarily capital costs, taxes and O&M expenses. After the investments related to the long-term supply plan are installed, the Company forecasts no major capital expenditures. All of our production assets will be positioned to provide service for the entire planning period with normal maintenance. Likewise, no major distribution investments are forecasted. In fact, our rate base and capital costs (net of the incremental costs of the interim and long-term options discussed above) may well decline gradually over the planning period as our depreciation reserve increases.

Q. WILL INCREASES IN O&M EXPENSES OVER THE PLANNING PERIOD MORE THAN OFFSET THE FLAT OR DECLINING CAPITAL COSTS?

A. The Company believes we can limit any O&M increases to modest levels. While general inflation may tend to increase our level of nominal O&M expenses, we are also assessing initiatives to reduce our expenses.

For example, in 2014 we developed a strategy to reduce expenses incurred from the Thermal Construction Department. By implementing operational efficiencies and reassigning certain responsibilities, the Zuni plant was able to reassign three mechanics and one Foreman to Xcel Energy's Transmission Organization. This reassignment was accomplished without the need to replace any of the positions, or increase any existing salaries or working hours. The result was O&M savings of approximately $155K, based on 2013 data. This dollar amount may appear to be small, but it represents about 1.5 percent of our most recently approved base cost of service.

Mr. Kutska cites another example of lower non-fuel O&M expenses in his testimony. Specifically, the Company estimates that the Company can reduce our annual O&M expense for maintaining backup fuel by $50K to $100K once Zuni is retired.

The Company will continue to explore additional efficiency/productivity initiatives to maintain a flat or declining cost of service over the planning period -- net of the incremental costs of our interim and long-term supply-side plans.

Q. HOW DID YOU ESTIMATE THE ALL-IN USAGE RATES FOR THE TYPICAL STEAM CUSTOMER?

A. The estimated all-in usage rates consist of the base usage and demand charges plus the SCA. We exclude the S&F charge.

Q. HOW DID YOU ESTIMATE THE BASE USAGE CHARGES?

A. The estimated base usage and demand charges during any given year were calculated by comparing the base revenue requirements (cost) for that year to the expected revenues for that same year based on the rates to be implemented January 1, 2015. Specifically, for any year the percentage difference between the expected revenues under the rates implemented on January 1, 2015, and the projected revenue requirements equals the increase to base rates for that year. This is the typical approach used in rates cases to determine the General Rate Schedule Adjustment ("GRSA").

Q. HOW DID YOU ESTIMATE THE SCA FOR EACH YEAR?

A. The SCA estimates are based on long-term forecasts of natural-gas prices. Under the scenarios where we add one or two boilers, the projected commodity costs also incorporate the efficiency gains of the new boilers. While 20-year forecasts are obviously subject to considerable uncertainty, they provide some guidance regarding long-term rates for steam service.

Q. HOW WERE THE BASE RATES AND SCA COMBINED TO DERIVE AN ALL-IN USAGE CHARGE?

A. The base usage charge and SCA are already assessed on each Mlb of customer use. The demand charge is assessed on a customer's peak hourly use during the billing period (or 50 percent of the customer's maximum hourly demand during the preceding 11 billing periods), so I converted this charge to a usage charge based on the load profile for a typical customer. The all-in usage charge is the sum of the base usage charge, base demand charge and SCA.

Q. WHAT BILLING DETERMINANTS DID YOU ASSUME WHEN DERIVING THE ALL-IN USAGE RATES UNDER THE TWO NEW BOILERS OPTION?

A. For the Two New Boilers Option we assumed no changes to the test-year billing determinants used to design the rates approved in Proceeding No. 12AL-1269ST. While we know that annual customer use will fluctuate to some degree from 2015 through 2034, the Two New Boilers Option corresponds to a scenario of little load loss. Consequently, the assumption of no load changes is reasonable for the purpose of estimating long-term rates.

Q. WHAT BILLING DETERMINANTS DID YOU ASSUME WHEN DERIVING THE ALL-IN USAGE RATES UNDER THE ONE NEW BOILER OPTION?

A. The One New Boiler Option corresponds to a Design Hour System Coincident Peak Load of between 312 Mlb and 443 Mlb, which represents a range of 131 Mlb. The Company calibrated its billing determinants to the maximum load of 443 Mlb minus 25 percent of 131 Mlb -- or 410 Mlb This amount represents a reduction of about 20 percent (or 105 Mlb) from our current Design Hour System Coincident Peak Demand. We assumed that about 52 Mlb of the reduction would be attributable to customer attrition; about 27 Mlb would be attributable to customer energy-efficiency initiatives; and about 27 Mlb would be attributable to customer initiatives to reduce their peak loads. The billing determinants were reduced consistent with these assumptions.

Q. WHY DID YOU ASSUME THAT THE BILLING DETERMINANTS WOULD BE CLOSER TO THE HIGH END OF THE RANGE CORRESPONDING TO THE ONE NEW BOILER OPTION RATHER THAN AT THE MIDPOINT OF THE RANGE?

A. If the Company was strictly a passive observer, then the midpoint of the range would probably be the most reasonable assumption. But, as explained above, the Company has some ability to shape our system loads. While we may never be able to adjust loads to their optimal levels -- or the levels at which customer demand is perfectly calibrated to our production capacity – we should be able to obtain a result better than the midpoint of the range. Once we decide on how many boilers to install, we can tailor our efforts accordingly.

Q. DID YOU ASSUME THE REDUCTIONS IN BILLING DETERMINANTS EXPLAINED ABOVE WOULD BE REDUCED IN ONE YEAR?

A. No. Customers will probably not be able or inclined to respond immediately to the new three-part rate design or the general increases in all-in rates (attributable to increased Zuni costs in the short term and the new boiler or boilers in the long term). Consequently, the Company assumed that customers will either: (1) convert to natural gas; or (2) remain on the steam system but reduce their peak steam loads gradually from 2016 through 2020.

Q. HOW DID YOU APPORTION THE REDUCTION IN BILLING DETERMINANTS OF 105 MLB. UNDER THE ONE NEW BOILER OPTION AMONG CUSTOMER MIGRATION, ENERGY-EFFICIENCY INITIATIVES, AND PEAK-SHAVING INITIATIVES?

A. We used an iterative method. We first modeled the billing determinants by assuming that only energy-efficiency and peak-shaving initiatives would contribute to the 105 Mlb. reduction. (In this first iteration we assumed no load reduction from customer migration.) We then derived the nominal and real all-in usage rates for each year based on these reduced billing determinants and the annual revenue requirements. The average real usage rate from 2016 through 2025 was $24.32 per Mlb.

For the second iteration we used our customer financial model, which I describe in more detail later in my testimony, to estimate the load reductions from customer migration assuming an all-in usage rate for steam service of $24.32 per Mlb. This estimated load loss was 52 Mlb. We then reran the nominal and real all-in usage rates assuming the total load reduction of 105 Mlb. was apportioned as follows: 52 Mlb. of load reductions from customer migration; 27 Mlb. of load reductions from energy-efficiency initiatives; and 27 Mlb. of load reductions from peak-shaving initiatives. The average real all-in usage rate from 2016 through 2025 based on this reapportionment of the assumed load reduction increased slightly to $24.80 per Mlb.

Because the average real usage rate increased by only $0.48 per Mlb. in this second iteration, the Company decided no further iterations were necessary. Stated differently, our financial modeling suggests a reasonably stable equilibrium price of $24.80 per Mlb. commensurate with customer migration of 52 Mlb. and a total load reduction of 105 Mlb.

Q. DO YOUR ESTIMATES OF CUSTOMER MIGRATION REFLECT ANY LOAD ADDITIONS, SUCH AS THE POTENTIAL NEW LOAD THAT MR. KUTSKA DISCUSSES?

A. No. By assuming no additional customers our financial modeling may overstate the net load migration under any assumed rate for steam service. But taking a conservative approach, *i.e.*, potentially overstating the net customer loss, is preferable for purposes of this exercise.

Q. WHEN DETERMINING THE ALL-IN USAGE RATE TO USE IN YOUR FINANCIAL MODELING, WHY DID YOU SELECT THE AVERAGE ANNUAL REAL RATE FROM 2016 THROUGH 2025?

A. As I mentioned previously when discussing the 2015 SCA, we hope and expect that customers will evaluate the economic viability of conversions to natural-gas service based on projected steam rates over the long term. While customers may be reluctant to base decisions on 20-year rate projections, they should be willing to consider 10-year projections when assessing long-term investments even if their payback periods are shorter. Based on this premise, the Company derived the average real all-in usage rate from 2016 through 2025 for the One New Boiler Option.

Q. WHY DID THE ALL-IN USAGE RATE INCREASE FROM THE FIRST ITERATION TO THE SECOND ITERATION?

A. Customers who remain on the system but reduce their annual use or billing demand have less impact on our base revenues than customers who leave the system entirely. Both iterations reflect the same annual revenue requirements and total load reduction of 105 Mlb. The difference is that the second iteration assumes 52 Mlb of load reduction from customers leaving the system, whereas the first iteration assumes no loss of customers. Consequently, billing determinants and base revenues are less under the second iteration than the first iteration. A higher rate is required to recover the same revenue requirement with fewer billing determinants.

Q. WHAT BILLING DETERMINANTS DID YOU ASSUME WHEN DERIVING THE ALL-IN USAGE RATES UNDER THE NO NEW BOILER OPTION?

A. We assumed a Design Hour System Coincident Peak Load of 279 Mlb, which represents the maximum load we could accommodate without adding a new boiler minus 40 Mlb, which is the same difference between actual and optimal customer loads that we assumed for the One New Boiler Option. That Design Hour System Coincident Peak Load represents a reduction of about 236 Mlb, or about 46 percent, from our current Design Hour System Coincident Peak Load of 515 Mlb. Obviously, this scenario is premised on a significant reduction in peak demand attributable to a combination of customer conversions to natural gas and customer load-reduction efforts. In this scenario the Company assumes that 60 Mlb of this reduction is attributable to customer conversions to natural gas; 88 Mlb is attributable to customers' energy-efficiency initiatives; and 88 Mlb is attributable to customers' peak-shaving initiatives.

Q. HOW DID YOU DETERMINE THE APPORTIONMENT OF THE ASSUMED LOAD REDUCTION AMONG CUSTOMER MIGRATION, ENERGY-EFFICIENCY INITIATIVES AND PEAK-SHAVING INITIATIVES?

A. We used the same approach outlined above for the One New Boiler Scenario. As was the case for the One New Boiler Option, we reached a reasonably stable outcome after two iterations for the No New Boiler Option.

Q. PLEASE SUMMARIZE THE ESTIMATED ALL-IN REAL USAGE RATES AND LOAD REDUCTIONS UNDER THE NO NEW BOILER OPTION AND ONE NEW BOILER OPTION.

A. The real all-in usage rates and load reductions under the two scenarios are provided in the table below.

Table 2 - All-In Usage Rates & Peak Load Reductions

	No New Boiler Option	One New Boiler Option
10 Year Average Real All-In Rate	$25.27	$24.80
Design Day Peak Reduction from:		
Customer Migration	60 Mlb	52 Mlb
Peak Shaving Activities	88 Mlb	27 Mlb
Energy Efficiency Activities	88 Mlb	27 Mlb
Total Peak Reduction	236 Mlb	105 Mlb

Q. DID YOU CONDUCT A SIMILAR ANALYSIS FOR THE TWO NEW BOILERS OPTION?

A. No. This scenario necessarily assumes a long-term peak load similar to today's peak load. This assumption of steady load may or may not be realistic given the projected increases in revenue requirements resulting from the addition of two boilers. Over the next 18 months we should gain a better understanding of likely load changes. Regardless, it would make no sense to model all-in usage rates under the assumption of load reductions that would by themselves eliminate the need for two new boilers. Consequently, the Company did not conduct any financial modeling for this scenario – other than estimating the all-in usage rates assuming no load changes.

Q. YOU MENTIONED THAT YOU USED A CUSTOMER FINANCIAL ANALYSIS TO ESTIMATE CUSTOMER MIGRATION UNDER VARIOUS ALL-IN USAGE RATES. PLEASE EXPLAIN THIS MODELING AT A HIGH LEVEL.

A. While the modeling is data-intensive, the basic exercise is straightforward. We first estimated each customer's cost of converting to natural gas and the difference between the customer's annual bills for steam and gas service. Based on these estimates we could determine if conversion to natural gas could pay for itself within four years. The support for this analysis is provided as Attachment No. SBB-4.

Q. IS IT IMPORTANT TO UNDERSTAND THE INHERENT LIMITS OF SUCH MODELING?

A. Yes. Any such analyses are fraught with uncertainty. For example, a customer's decision to either convert to natural gas or remain on the steam system is influenced by many factors and is not easily captured in static financial analyses. Even to the extent customer decisions can be traced to rate or bill changes, one-time bumps or dips in rates or bills are probably less important than the long-term rates or bills. Moreover, as explained earlier, the Company is not strictly a passive observer of customer responses to price increases. We can work with customers to help them moderate their impacts.

Similarly, the extent to which customers who remain on the steam system reduce their peak loads in response to the new rate design or changes in all-in usage rates is unknown.

Q. GIVEN THESE CAVEATS, DID THE COMPANY EVALUATE LIKELY CUSTOMER RESPONSES TO VARIOUS LEVELS OF ALL-IN STEAM USAGE RATES?

A. Yes. We estimated how many customers (and how much load) would migrate to natural-gas service under rates as low as of \$20/Mlb and as high as \$30/Mlb. For purposes of this analysis we assumed that a typical customer would require a payback period of no more than four years. The resulting estimated load loss in terms of billing demand and annual use are provided in Attachment No. SBB-5. The projected reductions to system peak load assuming an average required payback period of four years range from 4 percent at \$20/Mlb. to 25 percent at \$30Mlb. The reductions in projected energy use range from 7 percent at \$20/Mlb to 41 percent at \$30/Mlb. As explained above, we used this same analysis to estimate load reductions attributable to customer migration under the No New Boiler Option and One New Boiler Option.

Q. WHY DID YOU DECIDE TO IMPUTE A REQUIRED PAYBACK PERIOD OF FOUR YEARS?

A. This payback period is based on our own studies of customers' required payback periods for implementing energy-efficiency initiatives, national surveys of required customer payback periods for implementing energy-efficiency initiatives, and the results of the survey of our steam customers that Ms. Wozniak sponsors. The various payback periods suggested by these surveys are summarized in Attachment No. SBB-6. Notably, all of the surveys suggest that customers typically target or require a maximum payback period of around four years.

Consequently, the Company has a strong empirical basis for using a four-year payback period. Obviously, customers who can accept longer payback periods than the average of four years are more likely to leave the system than our financial modeling suggests. Likewise, customers who demand shorter payback periods are less likely to leave than our financial modeling suggests. Our sense is that the under-estimates and over-estimates of customer load loss will roughly offset each other.

Q. IS THE COMPANY SUGGESTING THAT THE LOAD LOSSES RESULTING FROM THESE ANALYSES REPRESENT THE BEST ESTIMATES OF CHANGES TO SYSTEM PEAK LOAD OR BILLING DEMANDS?

A. No. As explained above, even customers who remain on the steam system will most likely adjust their peak loads and use in response to the upcoming rate-design changes and changes in all-in usage rates. These load impacts must be added to the losses stemming from customer conversions. On the other hand, while the Company encourages customer efforts to reduce their use or peak loads, we hope to take steps to mitigate the loss of load attributable to customer conversions. Our bottom-line assessment of likely system peak loads under various scenarios attempts to account for all of these impacts.

Q. HOW DID YOU USE THE RESULTS FROM YOUR SURVEY OF STEAM CUSTOMERS TO TEST THE RESULTS OF YOUR INTERNAL FINANCIAL ANALYSIS?

A. The customer survey sponsored by Ms. Wozniak included one question to specifically test customer sensitivity to price increases. The results suggested that a 10 percent price increase would prompt about 18 percent of our customers to leave the steam system. An increase of 20 percent would prompt about 36 percent of customers to leave the system. An increase of 30 percent would prompt about 55 percent of customers to leave the system.

To put these percentage increases into perspective, the current all-in steam usage rate is $19.114 per Mlb. A 10 percent increase would result in an all-in usage rate of $21.025 per Mlb; a 20 percent increase would result in an all-in usage rate of $22.937 per Mlb.; and a 30 percent increase would result in an all-in usage rate of $24.848 per Mlb. In contrast, our financial modeling suggests a load reduction at an all-in usage rate of $24.80 per Mlb. – or at a level about 30 percent above current rates -- of only about 10 percent. Based strictly on a comparison of these percentages, the survey results indicate more price sensitivity than the Company's financial modeling.

Q. CAN YOU RECONCILE THESE DIFFERENCES?

A. Given all the uncertainties, I would be surprised if any two tools for measuring customer response would yield the same results. But I would highlight two important caveats when comparing the two results.

The first caveat is that 17 percent of the survey respondents indicated they would convert to natural gas even at current steam rates. Over the next 18 months the Company will gather data on actual customer decisions. But if 17 percent of our customers would truly leave the system at current rates, then the incremental impact of a 10 percent rate increase on customer migration would be only about 1 percent. The incremental impact of a 20 percent rate increase on customer migration would be about 19 percent (36 percent minus 17 percent). The incremental impact of a 30 percent rate increase on customer migration would be about 38 percent (55 percent minus 17 percent). While the impacts of 20 percent and 30 percent rate increases are greater based on the survey results than our financial modeling indicates, the elimination of the 17 percent impact under current rates brings them closer.

The second caveat is that the survey results have clear limitations. Ms. Wozniak discusses these limitations in her Direct Testimony. I would add only that the survey is probably more useful for gathering qualitative information – such as how satisfied customers are with their steam service or Xcel Energy as a whole or what customers value most in steam service – than for determining specific customer responses to certain prices. For the most part individual customers would need to evaluate the costs of alternative service before reaching any financial decisions. It is unclear how many customers had access to good and recent information on these costs.

Q. GIVEN THIS DISCUSSION, DOES THE COMPANY BELIEVE THE RESULTS OF ITS MODELING SHOULD BE MODIFIED?

A. No. The financial modeling is probably a more accurate barometer for assessing specific customer financial decisions than the survey results. Nonetheless, the survey results do suggest that customer responses to price increases are probably not linear, and that the Company should evaluate carefully whether prices will reach a tipping point at levels lower than our modeling suggests.

Q. YOU HAVE PROJECTED LOAD LOSSES UNDER VARIOUS ALL-IN RATES. DO YOU BELIEVE THESE RESULTS SHED LIGHT ON WHICH OF THE THREE LONG-TERM OPTIONS IS MOST OR LEAST LIKELY?

A. Yes. The No New Boiler Option appears unlikely, as our Design Hour System Coincident Peak Load would need to decline by at least 40 percent. Load losses of this magnitude would occur only if customer responses to the new rate design and the rate increases necessitated by the least expensive of the remaining two options (the One New Boiler Option) drove significant conversions to natural gas. A loss of this magnitude under the One New Boiler Option appears unlikely, based on the customer migration predicted by our financial modeling. Moreover, as explained above, the Company would have the ability to reduce customer migration from steam service through long-term contracts, rate discounts, rate caps and/or energy-efficiency initiatives.

Q. WHAT IS THE BASIS FOR YOUR CONCLUSION?

A. Based on our financial modeling, we predict a load loss attributable to customer migration of about 10 percent. Even if we were unable to stem this reduction, peak demand would need to decline by about another 35 percent due to the energy-efficiency and peak-shaving initiatives of the customers who chose to remain on the system. While we expect some response, a response of that magnitude from remaining customers is unlikely. Absent concrete data confirming such load changes, they are much greater than the customer responses for which we would normally plan.

Consequently, we believe the No New Boiler Option is the least likely of the three supply-side scenarios. Nonetheless, the Company does not recommend eliminating any of the three scenarios at this time; we need to gather more data on customer responses to the new rate design and projected cost increase we are socializing in this filing before selecting a long-term supply-side option.

VIII. COST RECOVERY PLAN

Q. HOW DOES THE COMPANY PLAN TO RECOVER THE COST INCREASES ATTRIBUTABLE TO ITS INTERIM AND LONG-TERM PLANS?

A. In Attachment No. SBB-3 the Company has estimated the level of compensatory base rates for each year from 2015 through 2034, given forecasted changes to revenue requirements and billing determinants. These estimates are subject to considerable uncertainty, particularly due to the potential changes in billing determinants explained earlier in my testimony. Nonetheless, they serve as useful barometers of the need for base rate increases.

As indicated in Attachment No. SBB-3, the interim component of the Steam Plan would entail significant cost increases beginning in 2016. Reductions to billing determinants could exacerbate the 2016 revenue deficiency. Consequently, the Company would request a rate increase to recover the 2016 revenue deficiency soon after receiving a Commission Decision in this proceeding. The Commission approved rate change resulting from that Phase I proceeding would be implemented sometime in 2016.

The timing of additional rate changes in the future would depend on the long-term supply-side option selected and the associated changes in billing determinants. Under the No New Boiler Option, the Company's costs would decrease significantly from 2016 levels after the retirement of the Zuni station. However, this scenario assumes a pronounced reduction in billing determinants. The net impact of these two factors is unclear at this time.

Under the One New Boiler Option the Company would probably file to increase rates in late 2018 or early 2019 – to coincide with the installation of the new boiler. Again, the timing and magnitude of the rate increase would depend in part on the reductions to billing determinants under this scenario.

Under the Two New Boilers Option the Company would most likely not experience significant changes to billing determinants. Consequently, any future rate increase would be driven by the cost increases resulting from the two boilers. The Company would most likely seek to implement higher base rates rate sometime in late 2018 or early 2019 – around the date the new boilers are installed.

Q. WOULD THE COMPANY CONSIDER FILING FOR APPROVAL OF A MULTI YEAR PLAN TO COVER A SERIES OF PROJECTED ANNUAL REVENUE DEFICIENCIES?

A. Yes. A Multi Year Plan ("MYP") would dovetail well with the increased emphasis on and need for a long-term plan for the steam business. An MYP might be particularly attractive for the second of the two Phase I rate cases explained above under the One New Boiler Option and Two New Boilers Option. At that point we would have identified the optimal long-term supply-side option and the potential for additional lumpy cost increases would be minimal. Customers would benefit from base rate certainty, and the Company would be reasonably well positioned to manage the financial risks of committing to an MYP.

IX. <u>CUSTOMER BENEFITS</u>

Q. HOW DOES THE COMPANY'S PROPOSED STEAM RESOURCE PLAN AFFECT CUSTOMERS?

A. There is no question that the steam business is undergoing a transition. The potential need for significant investment in production facilities has highlighted the need for some significant business improvements – such as more thorough assessments of potential supply-side options, more thorough assessments of the potential impacts of cost increases on customer migration from steam service, more efficient pricing, and more frequent fuel cost adjustments. From a customer perspective, we believe the recently concluded Phase II proceeding and this Steam Resource Plan provide the best path for managing this transition from the current state to the preferred long-term state.

Admittedly, this transition plan does impose a short-term cost. There is little doubt most customers will experience price increases over the next five years. Some customers with low load factors will experience high percentage bill increases, while customers with high load factors may see only modest bill increases or even rate decreases. On average, though, we expect customer rates to increase.

Nonetheless, it is equally important to recognize the long-term customer benefits.

One important benefit is more reliable service. With some attention the Zuni plant can continue to provide service over a short period – until more reliable production facilities can be identified and installed. But as Mr. Farmer highlights, the continued operation of Zuni also imposes risks; from a reliability standpoint it is in customers' best interests to retire this plant relatively soon. After this retirement customers will be served by either two or three production plants – each of which will be well-positioned to provide reliable service for many years. Our request for contingent approval of a supply-side option in this proceeding will allow us to retire Zuni as expeditiously as possible.

Another benefit is long-term rate stability. After the transition period customer rates are expected to remain relatively stable. This stability is obviously very important to customers. Moreover, assuming at least one new boiler is required under the long-term component of the Steam Resource Plan, the higher efficiency of the new boiler(s) will reduce the SCA on an ongoing basis.

A third benefit is that the new rate design will encourage customers to opt for their most efficient energy alternatives. We hope that most current steam customers will conclude that steam service continues to be their best option, but natural gas may be a more cost-effective option in some cases. Sound long-term price signals are critical for promoting the efficient use of utility services.

Q. ASIDE FROM THESE BENEFITS TO STEAM CUSTOMERS, ARE THERE OTHER BENEFITS TO THE COMMUNITY AS A WHOLE?

A. Yes. The City of Denver is very interested in the Zuni site as part of its larger redevelopment efforts. Retiring Zuni from service will facilitate the City of Denver's ("City") plans for the area.

Q. MUST THE COMPANY WAIT UNTIL ZUNI IS RETIRED FROM STEAM SERVICE BEFORE FREEING UP SOME OF THE PARCELS ON THE SITE?

A. No. Several interim steps can be taken to advance the City's redevelopment plans for the area. For example, the Company plans to vacate the Maintenance Pool Building after we construct a replacement facility at the site of the Cherokee Station. We are also exploring the removal of the three storage tanks at the Zuni site. The Company plans to file for approval of an interim decommissioning plan for Zuni that would address the Maintenance Pool Building, storage tanks, and other various structures and land not required for steam service. Consequently, the site can be at least partially prepared for redevelopment prior to Zuni's retirement from steam service.

Q. DOES THE STEAM RESOURCE PLAN PROVIDE ANY OTHER COMMUNITY BENEFITS?

A. Once Zuni is retired, its production will be replaced by production from more efficient boilers. This more efficient production will reduce the environmental impacts of providing steam service in downtown Denver.

Q. DO THESE BENEFITS JUSTIFY THE TRANSITION COSTS?

A. Yes. Of course, a better scenario would be to obtain the long-term benefits for customers without the transition costs. But that scenario is unrealistic. In the long run customers will be much better off under the proposed Steam Resource Plan and pricing changes than if we did nothing and hoped for the best.

X. SUMMARY OF PLAN, TIMELINES AND REQUESTED APPROVALS

Q. CAN YOU PROVIDE A DIAGRAM OF THE VARIOUS COMPONENTS OF THE STEAM RESOURCE PLAN YOU HAVE PROPOSED IN THIS PROCEEDING?

A. Yes. The Steam Resource Plan comprises a wide variety of supply-side and demand-side analyses, as well as financial analyses that consider the impacts of both. A diagram of the various components of and inputs into the Steam Resource Plan is included as Attachment No. SBB-7.

Q. CAN YOU PROVIDE A TIMELINE OF THE APPROVALS AND MILESTONES YOU ARE REQUESTING?

A. Yes. The critical milestones underlying the Company's Steam Resource Plan and related filings are captured on the timeline below. Some of these dates can be pinpointed, while others are estimates. Nonetheless, the Company believes the Steam Resource Plan we are proposing in the proceeding can be implemented systematically and afford sufficient time for the preparation of filings, regulatory review of these filings, and the construction of any new facilities needed.

Table 3. Timeline

TIMELINE ELEMENTS	
Steam Plan Filing Date	18-Dec-14
Phase 2 Rate Implementation	1-Jan-15
Customer Notice to Opt-Out Deadline	31-Jan-15
Commission Decision in This Proceeding	Aug-15
Customers Opt Out exit Deadline	1-Oct-15

Phase I Filing	4th Quarter 2015
Phase I Rate Implementation	2nd Quarter 2016
Compliance Filing for Selection of Long-Term Option	Jul-16
Commission Approval of Long-Term Option	Sep-16
Zuni Capital Upgrade Installed	Oct-16
State Steam Plant Upgrade Installed	Nov 16
New Boiler(s) Installed	Oct 18

Q. WHAT SPECIFIC APPROVALS IS THE COMPANY REQUESTING IN THIS PROCEEDING?

A. The Company requests approval of our Steam Resource Plan, which includes two major components.

The first component is the interim plan to ensure reliable service over the next few years. Specifically, the Company requests approval of both our plans to ensure the reliable operation of Zuni from 2016 through at least 2018, and the upgrade to the State Steam Plant to provide higher pressure service. In conjunction with approval of the interim component, the Company requests a depreciation rate for the capital component of the Zuni upgrade of 20 percent. We believe that neither the Zuni nor State Steam Plant upgrade necessitates a CPCN. But to the extent the Commission determines that a CPCN is required for one or both initiatives, then the Company requests that the Commission grant any such CPCN(s).

The second component is the long-term plan. The Company seeks approval to select one of the three long-term supply-side alternatives we have identified in this proceeding. The Company is asking for a conditional CPCN for the One New Boiler Option at the Denver Steam Plant and the Two New Boilers Option at the Zuni site. It is also possible that the Company will determine that the No New Boiler Option is feasible; in that case, a CPCN will not be required because there will not be any need for the Company to construct new generation facilities. Over the next 18 months the Company would evaluate our customers' long-term needs. We would then submit a compliance filing on or before July 1, 2016, setting forth our Required Maximum Production Sendout and identifying the supply-side plan (No New Boiler Option, One New Boiler Option or Two New Boilers Option) that corresponds with these projected needs. We would request expedited approval of the selected option, as it would have already been approved as part of the approved Steam Resource Plan in this proceeding.

Q. IS YOUR DIRECT TESTIMONY CONCLUDED?

A. Yes.

Attachment A

Statement of Qualifications

Scott B. Brockett

I graduated from Otterbein College in 1980 with a Bachelor of Arts degree in English and Economics. I graduated from Miami University (Ohio) in 1981 with a Masters of Arts degree in Economics.

From August 1982 through February 1999 I was employed by the Minnesota Department of Public Service ("Department"), a state agency charged with developing energy policy and representing all customers in utility matters before the Minnesota Public Utilities Commission.

From August 1982 through May 1984 I was an analyst in the Computational Services Unit, where conducted economic analyses and reviewed telecommunications depreciation filings. From June 1984 through January 1991 I worked in the Energy Unit. My major areas of responsibility were buyback rates for Qualifying Facilities, rate design, embedded cost of service and marginal cost of service.

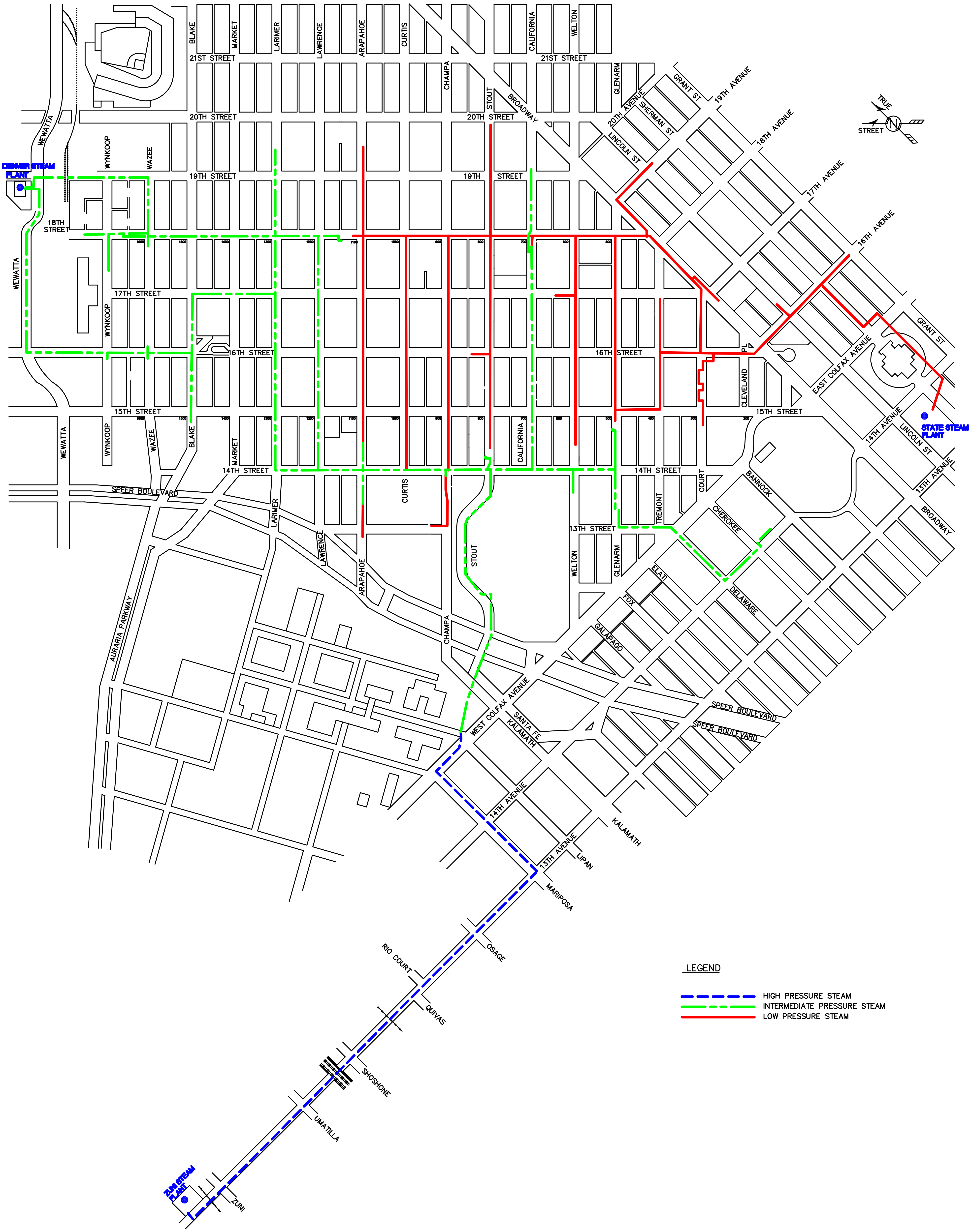
From January 1991 to August 1994 I held two similar supervisory positions. My primary responsibility was to oversee the Department Staff's advocacy in electric utility matters including general rate proceedings, integrated resource plans, demand-side management programs, and a wide variety of other regulatory issues.

In August 1994 I was promoted to Manager of Energy Planning and Advocacy. In this capacity the responsibilities I assumed as a supervisor were expanded to include natural gas advocacy, the development of state energy policy, and testifying on energy matters before the Minnesota Legislature. In December 1998 I was appointed Acting Assistant Commissioner of Energy. I held this position until February 1999.

From February 1999 to July 2004 I was employed by Consumers Energy ("Consumers"), an investor-owned utility providing natural-gas and electric service in Michigan, as Supervisor of Pricing and Revenue Forecasting. My primary responsibilities were developing prices for Consumers' electric and natural gas services, conducting economic analyses of various service options, evaluating the impact of Michigan's electric open-access program, estimating customer bills, and forecasting natural gas and electric revenue. I also managed Consumers' voluntary Green Power Pilot Program.

During my tenure with the Department I testified on demand-side management, rate design, embedded cost of service, marginal cost of service, and the environmental costs of electric generation. During my tenure with Consumers I testified on gas pricing issues and electric stranded costs.

I joined Xcel Energy as Manager, Gas Pricing and Planning, in July 2004. I assumed my current position in 2008. During my tenure with Xcel Energy I have testified on pricing and tariff issues in seven general rate cases (Proceeding Nos. 05S-264G, 06S-656G, 08S-146G, 09AL-299E, 10AL-963G, 11AL-947E and 14AL-0710ST). I have also testified on policy issues in proceedings involving steam service, electric interruptible service, electric Demand Side Management cost recovery and incentives, and distributed generation. In addition, I have testified on cost recovery issues related to the Pipeline System Integrity Adjustment, Clean Air Clean Jobs Act, the acquisition of various generating units, and distributed generation.


DENVER STEAM PLANT
STATE STEAM PLANT
ZUNI STEAM PLANT
TRUE
STREET
N
BLAKE
MARKET
LARIMER
LAWRENCE
ARAPAHOE
CURTIS
CHAMPA
STOUT
CALIFORNIA
WELTON
GLENARM
TREMONT
COURT
CLEVELAND
PL
21ST STREET
20TH STREET
19TH STREET
18TH STREET
17TH STREET
16TH STREET
15TH STREET
14TH STREET
13TH STREET
WEWATTA
WYNKOOP
WAZEE
BROADWAY
GRANT ST
SHERMAN ST
LINCOLN ST
20TH AVENUE
19TH AVENUE
18TH AVENUE
17TH AVENUE
16TH AVENUE
EAST COLFAX AVENUE
14TH AVENUE
13TH AVENUE
SPEER BOULEVARD
AURARIA PARKWAY
BANNOCK
CHEROKEE
DELAWARE
ELATI
FOX
GALAPAGO
WEST COLFAX AVENUE
SANTA FE
KALAMATH
LIPAN
MARIPOSA
OSAGE
RIO COURT
QUIVAS
SHOSHONE
UMATILLA
ZUNI
LEGEND
HIGH PRESSURE STEAM
INTERMEDIATE PRESSURE STEAM
LOW PRESSURE STEAM

Public Service's Compliance Index with Commission Decision No. C13-1549 as modified by Commission Decision No. C14-0068 in Proceeding No. 12A-1264ST – Specifically Ordering ¶ 22 through ¶ 32 – as Applicable to Public Service's New Application

Decision / Order	Witness and Attachments addressing each Order
1. *Establish by preponderance of the evidence a present or future need for the facility. Such need means that its presence will be an improvement that justifies its costs* *[Decision No. C13-1549, ¶ 22]*	The Direct Testimonies of Mr. Scott Brocket, Mr. Steve Kutska and Mr. Tim Farmer (along with Attachment No. TMF-1, CONFIDENTIAL Attachment No. TMF-2A, CONFIDENTIAL Attachment No. TMF-3A and CONFIDENTIAL Attachment No. TMF-4A) address the future long-term needs of the steam business along with the associated costs.
2. *Establish by preponderance of the evidence that existing facilities are not reasonably adequate and available to meet that need* *[Decision No. C13-1549, ¶ 22]*	Mr. Tim Farmer through his Direct Testimony and Attachment No. TMF-1 discusses the current status of the Zuni equipment. Mr. Steve Kutska through his Direct Testimony discusses the impact on the steam system if Zuni fails.
3. *Establish by preponderance of the evidence that the utility has evaluated alternatives to the proposed facility. All feasible as opposed to all conceivable alternatives should be evaluated* *[Decision No. C13-1549, ¶ 22]*	Mr. Tim Farmer provides information throughout his Direct Testimony and in CONFIDENTIAL Attachment Nos. TMF-2A, TMF-3A and TMF-4A regarding the alternatives that the Company evaluated.
4. *Additional analysis of the efficacy of a smaller plant or facilities is required* *[Decision No. C13-1549, ¶ 25]*	See #3 above.

5. *Adding capacity at other existing facilities* *Decision No. C13-1549, ¶ 29]*	Mr. Tim Farmer provides information throughout his Direct Testimony and in CONFIDENTIAL Attachment Nos. TMF-2A, TMF-3A and TMF-4A regarding the alternatives that the Company studied. In addition, Mr. Steve Kutska sponsors the updated Siting and Land Rights report documenting the Company's efforts to find other sites or facilities for a boiler.
6. *Investigating building lease options* *Decision No. C13-1549, ¶ 29]*	See #3 above.
7. *Working with the Denver Redevelopment Authority or other customers to provide space for a boiler* *[Decision No. C13-1549, ¶ 29]*	The Company has interpreted that by this requirement as directing the Company to work with various housing or redevelopment entities that might have space for a boiler. Mr. Steve Kutska discusses the interaction that the Company has had with other Stakeholders in his Direct Testimony.
8. *Investigate potential distributed steam generation and co-location options* *[Decision No. C13-1549, ¶ 29]*	See #3 and #7 above.
9. *Submit an analysis to determine the correct boiler sizes and capacities and the associated costs for a range of customer attrition and growth possibilities* *[Decision No. C13-1549, ¶ 29]*	Mr. Scott Brocket discusses the Company's approach to managing its steam business in the long-term as well as the range of customer attrition possibilities associated with the capacity options available to the Company in his Direct Testimony. Mr. Steve Kutska also supplements this information in his Direct Testimony.
10. *Assessment of how the steam system may operate at a substantially reduced level, potentially by utilizing only the remaining boilers at other Company facilities after Zuni is closed* *[Decision No. C13-1549, ¶ 29]*	Mr. Scott Brocket discusses the Company's approach to managing its steam business in the long-term including the option where no new facilities would be constructed. Mr. Steve Kutska discusses how the Company will plan for and determine its long-term production capacity requirements.

11. *Assess scenarios in which some steam customers transition to gas utility service and in which the Company exits from the steam business* *[Decision No. C13-1549, ¶ 29]*	Mr. Scott Brockett discusses the long-term plans that the Company has for its steam business in his Direct Testimony.
12. *Assess the potential for stabilizing customer load through long-term commitments from customers in exchange for specific rate arrangements or other commitments* *[Decision No. C13-1549, ¶ 30]*	Mr. Scott Brockett discusses the Company's current plans to pursue demand-side options in his Direct Testimony.
13. *Analyze the value of rate discounts and recommend whether such discounts should continue or whether different discounts should be offered in the future* *[Decision No. C13-1549, ¶ 30]*	See #12 above.
14. *Conduct a detailed survey of its steam customers addressing their needs, options and preferences for utility service* *[Decision No. C13-1549, ¶ 30]*	Ms. Jennifer Wozniak sponsors the survey and related attachments in her Direct Testimony. Mr. Scott Brockett discusses how the Company has used the results of the survey in its long-term plans for its steam business.
15. *Provide the Commission with a thorough analysis of the causal relationship between increased steam rates and customer erosion* *[Decision No. C13-1549, ¶ 30]*	Ms. Jennifer Wozniak provides testimony about the results of the survey and what customers espouse what they will do when faced with increased steam rates. Mr. Scott Brockett provides an update to the Customer Driver Analysis, which objectively assesses the relationship between customer erosion and increased steam rates.
16. *Delineate the impact on utility rates* *[Decision No. C13-1549, ¶ 30]*	Mr. Scott Brockett delineates the impact of the Company's proposal on rates in his Direct Testimony and Attachments.

17.*Delineate the magnitude of the underlying operating maintenance and capital costs [Decision No. C13-1549, ¶ 23]*	Mr. Tim Farmer sponsors CONFIDENTIAL Attachment Nos. TMF-3A and TMF-4A, which provide the Company's estimates of the capital costs and the operating and maintenance cost estimates respectively for all of the options that the Company evaluated.
18. *A determination of stranded costs is an issue that needs to be addressed in any future filing of a regulatory plan if any Decision No. C13-1549, ¶ 27]*	See #11 above.
19. *If a future regulatory proposal is filed, it should address the equitable balance of risks and benefits among steam customers, other customers subsidizing steam rates and Public Service's shareholders given the potential for customer attrition caused by an associated rate increase for service [Decision No. C13-1549, ¶ 32]*	Not applicable; the Company is not seeking approval of a regulatory plan impacting natural gas or electric service customers.

2 Boiler Option - Revenue Requirements & All-In Rates

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand @ Customer	Mlbs	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515
Meters		151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151
Billed Demand	Mlbs	106,313	106,313	106,313	106,313	106,313	106,313	106,313	106,313	106,313	106,313	106,313	106,313	106,313	106,313	106,313	106,313	106,313	106,313	106,313	106,313
Volumetric	Mlbs	928,121	928,121	928,121	928,121	928,121	928,121	928,121	928,121	928,121	928,121	928,121	928,121	928,121	928,121	928,121	928,121	928,121	928,121	928,121	928,121
Steam Cost of Service																					
Base Revenue Requirements	$000	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743
Zuni Extension	$000	$0	$2,886	$3,249	$3,298	$379	$356	$275	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capitol Plant Tie	$000	$0.00	$101	$324	$313	$303	$293	$284	$277	$272	$268	$263	$258	$253	$248	$243	$238	$233	$227	$222	$216
Sun Valley - 2 Boiler	$000	$0	$0	$135	$613	$5,640	$5,591	$5,548	$5,511	$5,481	$5,471	$5,484	$5,500	$5,517	$5,534	$5,553	$5,572	$5,593	$5,615	$5,638	$5,663
Total Cost of Service	$000	$10,743	$13,730	$14,452	$14,967	$17,065	$16,983	$16,850	$16,531	$16,496	$16,482	$16,490	$16,501	$16,513	$16,526	$16,539	$16,553	$16,569	$16,585	$16,603	$16,622
Revenue Deficiency																					
Revenues Under Current Rates	$000	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742	$10,742
Total Cost of Service	$000	$10,743	$13,730	$14,452	$14,967	$17,065	$16,983	$16,850	$16,531	$16,496	$16,482	$16,490	$16,501	$16,513	$16,526	$16,539	$16,553	$16,569	$16,585	$16,603	$16,622
Revenue Deficiency	$000	($1)	($2,988)	($3,710)	($4,225)	($6,323)	($6,241)	($6,108)	($5,789)	($5,754)	($5,740)	($5,748)	($5,759)	($5,771)	($5,783)	($5,797)	($5,811)	($5,826)	($5,843)	($5,861)	($5,880)
GRSA & Equivalent Rates																					
GRSA (Revenue Deficiency / Revenue from Current Rates)		0.0%	27.8%	34.5%	39.3%	58.9%	58.1%	56.9%	53.9%	53.6%	53.4%	53.5%	53.6%	53.7%	53.8%	54.0%	54.1%	54.2%	54.4%	54.6%	54.7%
Equivalent Rates																					
Service & Facilities Charge		$200	$256	$269	$279	$318	$316	$314	$308	$307	$307	$307	$307	$307	$308	$308	$308	$308	$309	$309	$309
Demand Charge	$/Mlbs	$40.00	$51.13	$53.81	$55.73	$63.54	$63.24	$62.74	$61.56	$61.42	$61.37	$61.40	$61.44	$61.49	$61.53	$61.58	$61.64	$61.69	$61.76	$61.82	$61.89
Consumption Charge	$/Mlbs	$6.60	$8.44	$8.88	$9.20	$10.49	$10.44	$10.36	$10.16	$10.14	$10.13	$10.13	$10.14	$10.15	$10.16	$10.16	$10.17	$10.18	$10.19	$10.20	$10.22
Steam Cost Adjustment																					
SCA	$/Mlbs	$10.38	$7.41	$7.60	$7.95	$7.92	$8.61	$9.25	$9.33	$9.60	$9.98	$10.16	$10.46	$10.68	$10.84	$11.21	$11.48	$11.73	$11.93	$12.23	$12.56
Typical Customer Bill																					
Nominal Dollars	$000	$153	$155	$162	$168	$184	$188	$191	$189	$191	$194	$195	$197	$199	$200	$203	$205	$206	$208	$210	$213
	percentage change		*1.1%*	*5.5%*	*9.2%*	*18.1%*	*18.8%*	*20.3%*	*18.9%*	*20.0%*	*21.1%*	*21.5%*	*22.5%*	*23.1%*	*23.5%*	*24.7%*	*25.4%*	*26.0%*	*26.5%*	*27.4%*	*28.3%*
Real Dollars (adj. for inflation)	$000	$153	$152	$156	$159	$170	$171	$171	$166	$164	$163	$161	$160	$159	$157	$156	$154	$153	$151	$150	$149
	percentage change		*-0.8%*	*1.7%*	*3.6%*	*10.8%*	*10.4%*	*10.3%*	*7.5%*	*6.7%*	*6.2%*	*5.1%*	*4.4%*	*3.3%*	*2.1%*	*1.6%*	*0.7%*	*-0.3%*	*-1.4%*	*-2.3%*	*-3.0%*
All In Usage Rates (Demand, Volume, SCA)																					
Nominal Dollars	$/Mlbs	$21.56	$21.70	$22.65	$23.53	$25.69	$26.29	$26.79	$26.54	$26.77	$27.14	$27.33	$27.64	$27.87	$28.05	$28.43	$28.71	$28.98	$29.19	$29.51	$29.86
	percentage change		*0.7%*	*5.0%*	*8.7%*	*17.5%*	*18.4%*	*19.9%*	*18.6%*	*19.6%*	*20.8%*	*21.2%*	*22.2%*	*22.8%*	*23.3%*	*24.5%*	*25.2%*	*25.8%*	*26.3%*	*27.2%*	*28.1%*
Real Dollars (adj. for inflation)	$000	$21.56	$21.30	$21.81	$22.24	$23.83	$23.93	$23.93	$23.26	$23.03	$22.91	$22.64	$22.47	$22.24	$21.96	$21.84	$21.65	$21.45	$21.20	$21.03	$20.88
	percentage change		*-1.2%*	*1.2%*	*3.1%*	*10.2%*	*9.9%*	*9.9%*	*7.1%*	*6.3%*	*5.9%*	*4.7%*	*4.0%*	*3.0%*	*1.8%*	*1.3%*	*0.4%*	*-0.5%*	*-1.7%*	*-2.5%*	*-3.2%*

Inflation Rate	1.90%

Ten Year Average Nominal All in Usage Rate	$25.44
Ten Year Average Real All in Usage Rate	$22.89
10 Year Average GRSA	50.1%
10 Year Average SCA	$8.78

Billed Demand to Volume Ratio

Average Customer	
Meters	1
Coincident Peak (1h)	3
Billed Demand	799
Volume	6,978
Load Factor	0

1 Boiler Option - Revenue Requirements & All-In Rates

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand @ Customer	Mlbs	515	486	458	431	420	410	410	410	410	410	410	410	410	410	410	410	410	410	410	410
Meters		151	147	142	138	133	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129
Billed Demand	Mlbs	106,313	101,353	96,505	91,767	89,155	86,543	86,543	86,543	86,543	86,543	86,543	86,543	86,543	86,543	86,543	86,543	86,543	86,543	86,543	86,543
Volumetric	Mlbs	928,121	872,674	818,448	765,416	729,613	693,811	693,811	693,811	693,811	693,811	693,811	693,811	693,811	693,811	693,811	693,811	693,811	693,811	693,811	693,811
Steam Cost of Service																					
Base Revenue Requirements	$000	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743
Zuni Extension	$000	$0	$2,886	$3,249	$3,298	$379	$356	$275	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capitol Plant Tie	$000	$0.00	$101	$324	$313	$303	$293	$284	$277	$272	$268	$263	$258	$253	$248	$243	$238	$233	$227	$222	$216
Sun Valley - 1 Boiler	$000	$0	$0	$135	$468	$3,667	$3,620	$3,578	$3,540	$3,506	$3,481	$3,467	$3,455	$3,443	$3,432	$3,421	$3,411	$3,401	$3,392	$3,383	$3,375
Total Cost of Service	$000	$10,743	$13,730	$14,452	$14,822	$15,092	$15,013	$14,881	$14,561	$14,522	$14,492	$14,473	$14,456	$14,439	$14,423	$14,407	$14,392	$14,377	$14,362	$14,348	$14,334
Revenue Deficiency																					
Revenues Under Current Rates	$000	$10,742	$10,167	$9,605	$9,055	$8,703	$8,352	$8,352	$8,352	$8,352	$8,352	$8,352	$8,352	$8,352	$8,352	$8,352	$8,352	$8,352	$8,352	$8,352	$8,352
Total Cost of Service	$000	$10,743	$13,730	$14,452	$14,822	$15,092	$15,013	$14,881	$14,561	$14,522	$14,492	$14,473	$14,456	$14,439	$14,423	$14,407	$14,392	$14,377	$14,362	$14,348	$14,334
Revenue Deficiency	$000	($1)	($3,563)	($4,847)	($5,767)	($6,388)	($6,661)	($6,529)	($6,209)	($6,170)	($6,140)	($6,121)	($6,104)	($6,088)	($6,071)	($6,055)	($6,040)	($6,025)	($6,010)	($5,996)	($5,982)
GRSA & Equivalent Rates																					
GRSA (Revenue Deficiency / Revenue from Current Rates)		0.0%	35.0%	50.5%	63.7%	73.4%	79.8%	78.2%	74.3%	73.9%	73.5%	73.3%	73.1%	72.9%	72.7%	72.5%	72.3%	72.1%	72.0%	71.8%	71.6%
Equivalent Rates																					
Service & Facilities Charge		$200	$270	$301	$327	$347	$360	$356	$349	$348	$347	$347	$346	$346	$345	$345	$345	$344	$344	$344	$343
Demand Charge	$/Mlbs	$40.00	$54.02	$60.18	$65.48	$69.36	$71.90	$71.27	$69.74	$69.55	$69.41	$69.32	$69.24	$69.16	$69.08	$69.00	$68.93	$68.85	$68.78	$68.72	$68.65
Consumption Charge	$/Mlbs	$6.60	$8.92	$9.93	$10.81	$11.45	$11.87	$11.76	$11.51	$11.48	$11.46	$11.44	$11.43	$11.41	$11.40	$11.39	$11.38	$11.36	$11.35	$11.34	$11.33
Steam Cost Adjustment																					
SCA	$/Mlbs	$10.38	$7.38	$7.56	$7.89	$8.01	$8.70	$9.35	$9.42	$9.69	$10.08	$10.26	$10.57	$10.79	$10.95	$11.32	$11.60	$11.85	$12.05	$12.35	$12.69
Typical Customer Bill																					
Nominal Dollars	$000	$153	$161	$174	$187	$196	$206	$209	$207	$208	$211	$212	$214	$215	$216	$218	$220	$222	$223	$225	$227
		percentage change	*4.9%*	*13.1%*	*19.6%*	*22.8%*	*26.9%*	*27.2%*	*25.5%*	*26.6%*	*27.6%*	*27.7%*	*28.5%*	*28.9%*	*29.2%*	*30.2%*	*30.7%*	*31.2%*	*31.5%*	*32.2%*	*32.9%*
Real Dollars (adj. for inflation)	$000	$153	$158	$168	$177	$182	$187	$187	$181	$179	$178	$175	$174	$171	$169	$168	$166	$164	$162	$160	$159
		percentage change	*2.9%*	*9.3%*	*14.2%*	*16.1%*	*18.8%*	*17.9%*	*14.9%*	*14.3%*	*13.7%*	*12.4%*	*11.7%*	*10.5%*	*9.3%*	*8.6%*	*7.6%*	*6.6%*	*5.3%*	*4.4%*	*3.5%*
All In Usage Rates (Demand,Volume,SCA)																					
Nominal Dollars	$/Mlbs	$21.56	$22.49	$24.38	$26.20	$27.40	$28.80	$29.27	$28.92	$29.14	$29.49	$29.64	$29.93	$30.13	$30.27	$30.62	$30.87	$31.10	$31.28	$31.57	$31.88
		percentage change	*4.3%*	*12.6%*	*19.0%*	*22.3%*	*26.4%*	*26.8%*	*25.2%*	*26.2%*	*27.2%*	*27.4%*	*28.2%*	*28.6%*	*28.9%*	*29.9%*	*30.4%*	*30.9%*	*31.3%*	*32.0%*	*32.7%*
Real Dollars (adj. for inflation)	$000	$21.56	$22.07	$23.48	$24.76	$25.41	$26.21	$26.15	$25.35	$25.07	$24.89	$24.56	$24.33	$24.04	$23.70	$23.52	$23.28	$23.02	$22.72	$22.49	$22.30
		percentage change	*2.4%*	*8.7%*	*13.6%*	*15.6%*	*18.3%*	*17.5%*	*14.5%*	*13.8%*	*13.3%*	*12.0%*	*11.3%*	*10.2%*	*8.9%*	*8.3%*	*7.3%*	*6.3%*	*5.0%*	*4.1%*	*3.3%*

Inflation Rate	1.90%

Ten Year Average Nominal All in Usage Rate	$27.57
Ten Year Average Real All in Usage Rate	$24.80
10 Year Average GRSA	68.8%
10 Year Average SCA	$8.84

Billed Demand to Volume Ratio

Average Customer	
Meters	1
Coincident Peak (1h)	3
Billed Demand	799
Volume	6,978
Load Factor	0

0 Boiler Option - Revenue Requirements & All-In Rates

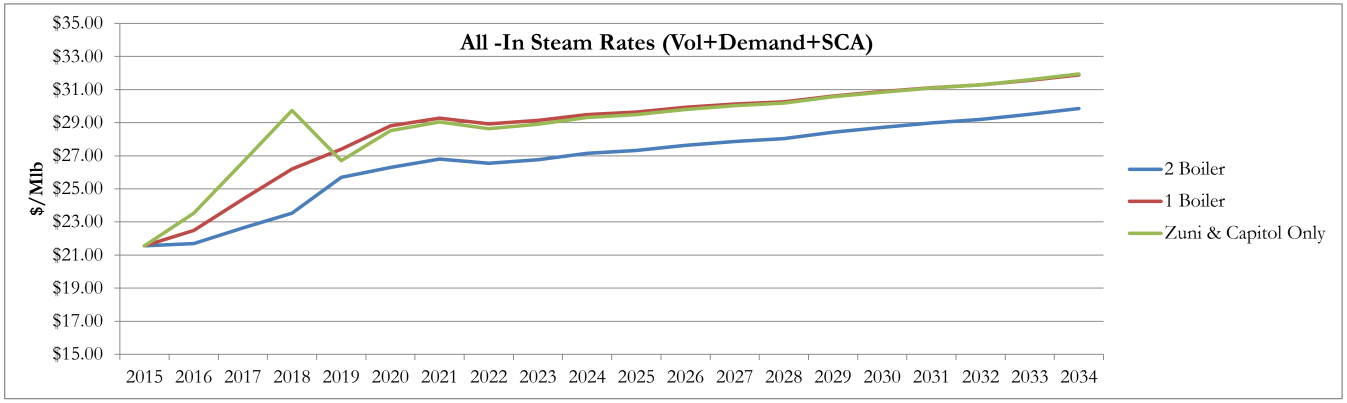
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand @ Customer	Mlbs	515	434	363	303	291	279	279	279	279	279	279	279	279	279	279	279	279	279	279	279
Meters		151	146	141	135	130	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Billed Demand	Mlbs	106,313	94,650	83,970	74,188	71,226	68,264	68,264	68,264	68,264	68,264	68,264	68,264	68,264	68,264	68,264	68,264	68,264	68,264	68,264	68,264
Volumetric	Mlbs	928,121	814,551	710,277	614,538	573,588	532,638	532,638	532,638	532,638	532,638	532,638	532,638	532,638	532,638	532,638	532,638	532,638	532,638	532,638	532,638
Steam Cost of Service																					
Base Revenue Requirements	$000	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743	$10,743
Zuni Extension	$000	$0	$2,886	$3,249	$3,298	$379	$356	$275	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capitol Plant Tie	$000	$0.00	$101	$324	$313	$303	$293	$284	$277	$272	$268	$263	$258	$253	$248	$243	$238	$233	$227	$222	$216
Sun Valley - Zuni & Capitol	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost of Service	$000	$10,743	$13,730	$14,317	$14,354	$11,425	$11,392	$11,302	$11,020	$11,015	$11,011	$11,006	$11,001	$10,996	$10,991	$10,986	$10,981	$10,976	$10,970	$10,965	$10,959
Revenue Deficiency																					
Revenues Under Current Rates	$000	$10,742	$9,514	$8,385	$7,350	$6,948	$6,547	$6,547	$6,547	$6,547	$6,547	$6,547	$6,547	$6,547	$6,547	$6,547	$6,547	$6,547	$6,547	$6,547	$6,547
Total Cost of Service	$000	$10,743	$13,730	$14,317	$14,354	$11,425	$11,392	$11,302	$11,020	$11,015	$11,011	$11,006	$11,001	$10,996	$10,991	$10,986	$10,981	$10,976	$10,970	$10,965	$10,959
Revenue Deficiency	$000	($1)	($4,217)	($5,931)	($7,005)	($4,477)	($4,845)	($4,755)	($4,473)	($4,468)	($4,464)	($4,459)	($4,454)	($4,449)	($4,444)	($4,439)	($4,434)	($4,429)	($4,423)	($4,418)	($4,412)
GRSA & Equivalent Rates																					
GRSA (Revenue Deficiency / Revenue from Current Rates)		0.0%	44.3%	70.7%	95.3%	64.4%	74.0%	72.6%	68.3%	68.3%	68.2%	68.1%	68.0%	68.0%	67.9%	67.8%	67.7%	67.6%	67.6%	67.5%	67.4%
Equivalent Rates																					
Service & Facilities Charge		$200	$289	$341	$391	$329	$348	$345	$337	$337	$336	$336	$336	$336	$336	$336	$335	$335	$335	$335	$335
Demand Charge	$/Mlbs	$40.00	$57.73	$68.29	$78.12	$65.77	$69.60	$69.05	$67.33	$67.30	$67.27	$67.24	$67.21	$67.18	$67.15	$67.12	$67.09	$67.06	$67.02	$66.99	$66.96
Consumption Charge	$/Mlbs	$6.60	$9.53	$11.27	$12.89	$10.86	$11.49	$11.40	$11.11	$11.11	$11.10	$11.10	$11.09	$11.09	$11.08	$11.08	$11.07	$11.07	$11.06	$11.06	$11.05
Steam Cost Adjustment																					
SCA	$/Mlbs	$10.38	$7.38	$7.54	$7.90	$8.32	$9.06	$9.74	$9.82	$10.10	$10.50	$10.69	$11.01	$11.24	$11.41	$11.80	$12.08	$12.35	$12.55	$12.87	$13.22
Typical Customer Bill																					
Nominal Dollars	$000	$153	$168	$191	$213	$191	$204	$207	$204	$206	$209	$210	$213	$214	$215	$218	$220	$222	$223	$225	$227
	percentage change		*9.7%*	*22.2%*	*31.3%*	*17.7%*	*26.5%*	*26.6%*	*24.7%*	*26.0%*	*27.1%*	*27.4%*	*28.2%*	*28.7%*	*29.0%*	*30.0%*	*30.6%*	*31.1%*	*31.5%*	*32.2%*	*33.0%*
Real Dollars (adj. for inflation)	$000	$153	$165	$183	$201	$177	$185	$185	$179	$178	$177	$174	$173	$171	$169	$167	$166	$164	$162	$160	$159
	percentage change		*7.7%*	*18.4%*	*26.2%*	*11.8%*	*18.2%*	*17.3%*	*14.1%*	*13.6%*	*13.2%*	*12.0%*	*11.3%*	*10.2%*	*9.0%*	*8.4%*	*7.5%*	*6.5%*	*5.3%*	*4.5%*	*3.7%*
All In Usage Rates (Demand,Volume,SCA)																					
Nominal Dollars	$/Mlbs	$21.56	$23.52	$26.63	$29.74	$26.71	$28.52	$29.04	$28.64	$28.92	$29.31	$29.49	$29.80	$30.02	$30.19	$30.56	$30.84	$31.10	$31.29	$31.60	$31.94
	percentage change		*9.1%*	*21.6%*	*30.7%*	*17.3%*	*26.1%*	*26.2%*	*24.4%*	*25.7%*	*26.8%*	*27.1%*	*27.9%*	*28.4%*	*28.7%*	*29.8%*	*30.4%*	*30.9%*	*31.3%*	*32.1%*	*32.8%*
Real Dollars (adj. for inflation)	$000	$21.56	$23.08	$25.65	$28.11	$24.77	$25.96	$25.94	$25.11	$24.87	$24.74	$24.43	$24.23	$23.95	$23.63	$23.48	$23.26	$23.01	$22.72	$22.52	$22.33
	percentage change		*7.1%*	*17.7%*	*25.5%*	*11.4%*	*17.8%*	*16.9%*	*13.7%*	*13.2%*	*12.8%*	*11.6%*	*10.9%*	*9.9%*	*8.7%*	*8.1%*	*7.2%*	*6.2%*	*5.1%*	*4.2%*	*3.4%*

Inflation Rate	1.90%

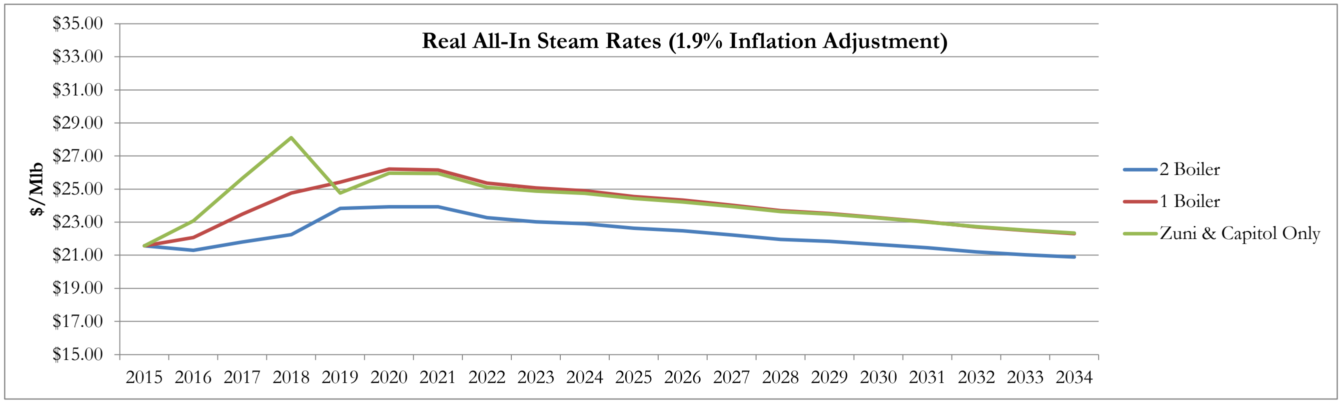
Ten Year Average Nominal All in Usage Rate	$28.05
Ten Year Average Real All in Usage Rate	$25.27
10 Year Average GRSA	69.1%
10 Year Average SCA	$9.10

Billed Demand to Volume Ratio

Average Customer	
Meters	1
Coincident Peak (1h)	3
Billed Demand	799
Volume	6,978
Load Factor	0



	2015-2026 Ave All-In
0 Boiler	$28.05
1 Boiler	$27.57
2 Boiler	$25.44



	2015-2026 Ave Real All-In
0 Boiler	$25.27
1 Boiler	$24.80
2 Boiler	$22.89

INPUTS

General

Base Year	2016
Pay Back Threshold	4 yrs
Steam to Gas	1.25mmBtu/Mlbs
Gas Conv. Escl	2.0%

Steam Riders

2016-2025 Average GRSA	62.82%	
2016-2025 Average SCA	$8.84/Mlbs	

Current Steam Rates

S&F	$200
Demand	$40/Mlbs-mo
Volumetirc	$6.60/Mlbs

Gas Riders

2016-2025 Ave GRSA	17.35%	
2016-2025 Ave GCA	$5.18/Dth	
2016-2025 Ave PSIA	$0.41/Dth	
2016-2025 Ave DSMCA	1.6%	

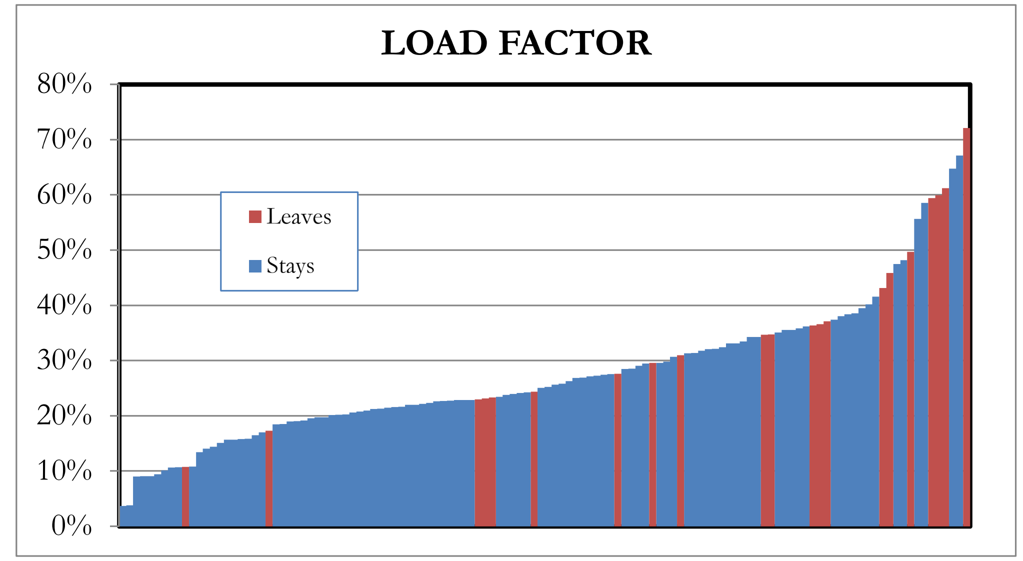
Current Gas Rates (CLG)

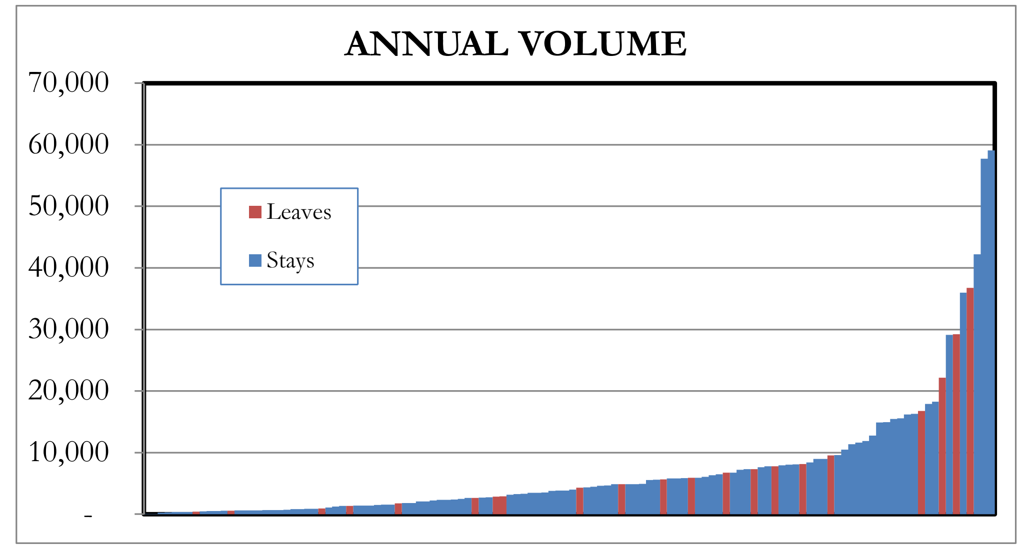
S&F	$65
Demand	$6.75/Dth
Volumetric	$0.19/Dth

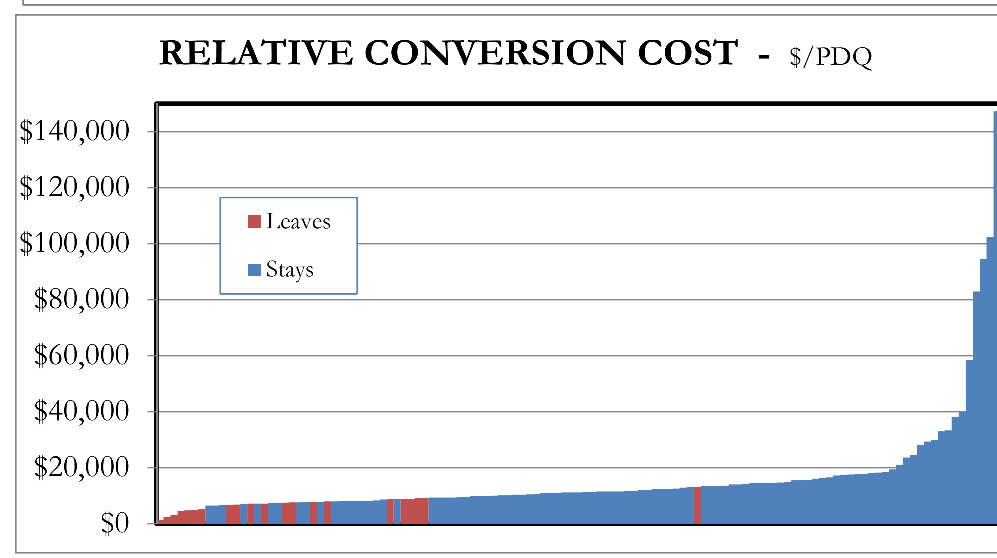
OUTPUTS

	2011-2012 Test Year	Conversion to Natural Gas	Remaining Steam Load
# of Customers	133	21	112
# of Meters	151	22	129
Billed Demand	106,313 Mlbs	13,061 Mlbs	93,253 Mlbs
Sales Volume	928,121 Mlbs	179,012 Mlbs	749,109 Mlbs
System Peak	425 Mlbs/hour	52 Mlbs/hour	373 Mlbs/hour
Load Factor	24.9%	39.1%	22.9%

Average All-In Steam Rate	$27.05
Average Real All-In Steam Rates	$24.42







CONFIDENTIAL INFORMATION HAS BEEN REDACTED

CONFIDENTIAL INFORMATION HAS BEEN REDACTED

4year Payback Results

Number	2016 Conversion Costs	4year Gas O&M Costs	4year Gas Billing	4year Avoided Steam Billing	**Net 4year Costs (Savings)**	Benefit Cost Ratio
77	[redacted]	[redacted]	[redacted]	[redacted]	**($899,724)**	1.4
3	[redacted]	[redacted]	[redacted]	[redacted]	**($594,038)**	1.4
41	[redacted]	[redacted]	[redacted]	[redacted]	**($244,054)**	1.7
63	[redacted]	[redacted]	[redacted]	[redacted]	**($221,108)**	1.2
19	[redacted]	[redacted]	[redacted]	[redacted]	**($179,732)**	1.2
30	[redacted]	[redacted]	[redacted]	[redacted]	**($110,636)**	1.2
95	[redacted]	[redacted]	[redacted]	[redacted]	**($79,465)**	1.0
43	[redacted]	[redacted]	[redacted]	[redacted]	**($52,566)**	1.4
46	[redacted]	[redacted]	[redacted]	[redacted]	**($50,464)**	1.1
105	[redacted]	[redacted]	[redacted]	[redacted]	**($45,976)**	1.2
4	[redacted]	[redacted]	[redacted]	[redacted]	**($44,099)**	1.1
40	[redacted]	[redacted]	[redacted]	[redacted]	**($40,105)**	1.9
45	[redacted]	[redacted]	[redacted]	[redacted]	**($39,341)**	1.1
56	[redacted]	[redacted]	[redacted]	[redacted]	**($37,923)**	1.3
114	[redacted]	[redacted]	[redacted]	[redacted]	**($32,170)**	1.1
75	[redacted]	[redacted]	[redacted]	[redacted]	**($25,848)**	1.1
60	[redacted]	[redacted]	[redacted]	[redacted]	**($22,395)**	1.0
92	[redacted]	[redacted]	[redacted]	[redacted]	**($15,484)**	1.3
44	[redacted]	[redacted]	[redacted]	[redacted]	**($13,134)**	1.0
22	[redacted]	[redacted]	[redacted]	[redacted]	**($9,398)**	1.0
53	[redacted]	[redacted]	[redacted]	[redacted]	**($4,573)**	1.0
85	[redacted]	[redacted]	[redacted]	[redacted]	**$7,273**	0.9
52	[redacted]	[redacted]	[redacted]	[redacted]	**$9,164**	1.0
33	[redacted]	[redacted]	[redacted]	[redacted]	**$11,425**	0.9
11	[redacted]	[redacted]	[redacted]	[redacted]	**$25,188**	1.0
16	[redacted]	[redacted]	[redacted]	[redacted]	**$34,606**	1.0
27	[redacted]	[redacted]	[redacted]	[redacted]	**$35,118**	0.7
13	[redacted]	[redacted]	[redacted]	[redacted]	**$36,206**	0.8
51	[redacted]	[redacted]	[redacted]	[redacted]	**$40,122**	0.7
123	[redacted]	[redacted]	[redacted]	[redacted]	**$40,480**	0.4
62	[redacted]	[redacted]	[redacted]	[redacted]	**$45,701**	0.9
107	[redacted]	[redacted]	[redacted]	[redacted]	**$49,977**	0.7
80	[redacted]	[redacted]	[redacted]	[redacted]	**$52,814**	0.8
9	[redacted]	[redacted]	[redacted]	[redacted]	**$53,381**	0.7
57	[redacted]	[redacted]	[redacted]	[redacted]	**$59,479**	0.9
101	[redacted]	[redacted]	[redacted]	[redacted]	**$60,048**	0.6
21	[redacted]	[redacted]	[redacted]	[redacted]	**$61,327**	0.9
93	[redacted]	[redacted]	[redacted]	[redacted]	**$61,902**	0.6
118	[redacted]	[redacted]	[redacted]	[redacted]	**$62,283**	0.9
64	[redacted]	[redacted]	[redacted]	[redacted]	**$63,409**	0.8
6	[redacted]	[redacted]	[redacted]	[redacted]	**$64,564**	0.8
99	[redacted]	[redacted]	[redacted]	[redacted]	**$65,732**	0.9
91	[redacted]	[redacted]	[redacted]	[redacted]	**$66,094**	0.6
59	[redacted]	[redacted]	[redacted]	[redacted]	**$66,196**	0.6
55	[redacted]	[redacted]	[redacted]	[redacted]	**$70,106**	0.5
61	[redacted]	[redacted]	[redacted]	[redacted]	**$72,790**	0.9
88	[redacted]	[redacted]	[redacted]	[redacted]	**$79,948**	0.6
8	[redacted]	[redacted]	[redacted]	[redacted]	**$80,941**	0.6
98	[redacted]	[redacted]	[redacted]	[redacted]	**$83,895**	0.7
109	[redacted]	[redacted]	[redacted]	[redacted]	**$90,929**	0.6
73	[redacted]	[redacted]	[redacted]	[redacted]	**$93,452**	0.7
65	[redacted]	[redacted]	[redacted]	[redacted]	**$97,467**	0.7
72	[redacted]	[redacted]	[redacted]	[redacted]	**$99,007**	0.7
58	[redacted]	[redacted]	[redacted]	[redacted]	**$103,620**	0.9
66	[redacted]	[redacted]	[redacted]	[redacted]	**$104,677**	0.4
71	[redacted]	[redacted]	[redacted]	[redacted]	**$108,292**	0.8
29	[redacted]	[redacted]	[redacted]	[redacted]	**$110,689**	0.7
39	[redacted]	[redacted]	[redacted]	[redacted]	**$116,160**	0.7
68	[redacted]	[redacted]	[redacted]	[redacted]	**$119,134**	0.4
32	[redacted]	[redacted]	[redacted]	[redacted]	**$121,899**	0.7
54	[redacted]	[redacted]	[redacted]	[redacted]	**$131,659**	0.6
81	[redacted]	[redacted]	[redacted]	[redacted]	**$134,464**	0.7
20	[redacted]	[redacted]	[redacted]	[redacted]	**$142,277**	0.8
124	[redacted]	[redacted]	[redacted]	[redacted]	**$160,372**	0.6
82	[redacted]	[redacted]	[redacted]	[redacted]	**$172,496**	0.4
38	[redacted]	[redacted]	[redacted]	[redacted]	**$172,990**	0.8
100	[redacted]	[redacted]	[redacted]	[redacted]	**$176,506**	0.8
69	[redacted]	[redacted]	[redacted]	[redacted]	**$188,987**	0.4
84	[redacted]	[redacted]	[redacted]	[redacted]	**$193,843**	0.8

4year Payback Results

Number	2016 Conversion Costs	4year Gas O&M Costs	4year Gas Billing	4year Avoided Steam Billing	**Net 4year Costs (Savings)**	Benefit Cost Ratio
103	[redacted]	[redacted]	[redacted]	[redacted]	**$198,365**	0.8
17					**$202,452**	0.7
25					**$205,804**	0.6
74					**$230,199**	0.9
31					**$232,655**	0.4
23					**$241,322**	0.7
12					**$242,868**	0.7
89					**$242,870**	0.7
48					**$247,722**	0.2
7					**$266,942**	0.8
49					**$271,949**	0.7
47					**$272,725**	0.7
87					**$275,118**	0.8
97					**$284,490**	0.6
90					**$291,308**	0.7
117					**$301,486**	0.8
116					**$312,272**	0.9
67					**$317,411**	0.6
119					**$341,731**	0.6
18					**$357,811**	0.5
36					**$368,624**	0.1
111					**$381,508**	0.8
26					**$384,764**	0.6
34					**$452,003**	0.8
127					**$457,439**	0.4
70					**$464,747**	0.6
96					**$486,779**	0.6
24					**$488,748**	0.4
108					**$496,315**	0.8
115					**$542,957**	0.4
110					**$558,089**	0.8
113					**$580,478**	0.9
112					**$738,243**	0.5
128					**$768,932**	0.2
15					**$813,355**	0.4
86					**$852,906**	0.6
50					**$900,760**	0.5
42					**$947,770**	0.1
129					**$956,668**	0.6
14					**$1,016,046**	0.5
102					**$1,051,019**	0.7
28					**$1,101,573**	0.2
83					**$1,118,296**	0.1
37					**$1,215,552**	0.4
2					**$1,216,387**	0.4
78					**$1,274,531**	0.8
106					**$1,294,080**	0.5
5					**$1,384,300**	0.3
35					**$1,509,326**	0.5
125					**$1,637,701**	0.5
94					**$1,902,304**	0.5
1					**$2,188,099**	0.6
76					**$5,631,816**	0.5
AVERAGE	$817,522	$62,127	$244,062	($780,625)	$343,086	0.7

.

								Steam To Gas Conversion Factor 1.25mmBtu/Mlbs			
Decision Year 2016			STEAM 2011-2012 Test Year Billing Determinants					NATURAL GAS 2011-2012 Test Year Billing Determinants		NATURAL GAS CONVERSION COST INPUTS	
Payback Criteria 4											
Acct No.	Customer	Address	# Meters	Billed Demand	Annual Volume	Max Day	1hour Coincident Peak	PDQ	Annual mmBtu	2016 Conv Cost	O&M Rate
	1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	3		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	4		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	5		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	6		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	7		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	8		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	10		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
	11		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	12		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	13		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	14		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	15		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	16		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	17		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	18		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	19		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	20		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	21		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	22		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	23		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	24		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	25		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	26		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	27		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	28		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	29		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	30		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	31		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	32		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	33		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	34		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	35		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	36		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION
HAS BEEN REDACTED

Decision Year	2016
Payback Criteria	4

Acct No.	Customer	Address	STEAM 2011-2012 Test Year Billing Determinants					Steam To Gas Conversion Factor 1.25mmBtu/Mlbs — NATURAL GAS 2011-2012 Test Year Billing Determinants		NATURAL GAS CONVERSION COST INPUTS	
			# Meters	Billed Demand	Annual Volume	Max Day	1hour Coincident Peak	PDQ	Annual mmBtu	2016 Conv Cost	O&M Rate
	37		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	38		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	39		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	40		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	41		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	42		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	43		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	44		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	45		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	46		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	47		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	48		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	49		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	50		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	51		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	52		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	53		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	54		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	55		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	56		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	57		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	58		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	59		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	60		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	61		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	62		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	63		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	64		1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	65		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	66		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	67		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	68		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	69		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	70		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	71		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	72		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	73		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	74		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	75		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION
HAS BEEN REDACTED

Decision Year	2016
Payback Criteria	4

			STEAM 2011-2012 Test Year Billing Determinants					NATURAL GAS 2011-2012 Test Year Billing Determinants (Steam To Gas Conversion Factor 1.25mmBtu/Mlbs)		NATURAL GAS CONVERSION COST INPUTS	
Acct No.	Customer	Address	# Meters	Billed Demand	Annual Volume	Max Day	1hour Coincident Peak	PDQ	Annual mmBtu	2016 Conv Cost	O&M Rate
	76		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	77		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	78		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	79		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
	80		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	81		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	82		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	83		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	84		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	85		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	86		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	87		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	88		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	89		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	90		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	91		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	92		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	93		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	94		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	95		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	96		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION HAS BEEN REDACTED

Decision Year	2016
Payback Criteria	4

Acct No.	Customer	Address	STEAM 2011-2012 Test Year Billing Determinants					NATURAL GAS 2011-2012 Test Year Billing Determinants (Steam To Gas Conversion Factor 1.25mmBtu/Mlbs)		NATURAL GAS CONVERSION COST INPUTS	
			# Meters	Billed Demand	Annual Volume	Max Day	1hour Coincident Peak	PDQ	Annual mmBtu	2016 Conv Cost	O&M Rate
97			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
98			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
99			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
100			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
101			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
102			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
103			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
104			2	[redacted]	[redacted]	[redacted]	[redacted]				
105			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
106			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
107			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
108			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
109			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
110			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
111			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
112			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
113			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
114			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
115			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
116			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
117			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
118			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
119			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
120			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
121			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
122			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
123			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
124			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
125			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
126			[redacted]	[redacted]	[redacted]	[redacted]	-				
127			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
128			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
129			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL YEAR			**146**	**103,236**	**911,859**	**9,030**	**418**	**10,564**	**1,086,014**	**$ 99,737,743**	

CONFIDENTIAL INFORMATION
HAS BEEN REDACTED

CONFIDENTIAL INFORMATION HAS BEEN REDACTED

	Natural Gas Billing	Natural Gas Billing		
S&F	$65	$65	$65	$65
Demand	$6.75/Dth	$6.75/Dth	$6.75/Dth	$6.75/Dth
Volumetric	$0.19/Dth	$0.19/Dth	$0.19/Dth	$0.19/Dth
GRSA	17%	17%	17%	17%
GCA	$5.18/Dth	$5.18/Dth	$5.18/Dth	$5.18/Dth
PSIA	$0.41/Dth	$0.41/Dth	$0.41/Dth	$0.41/Dth
DSMCA	1.6%	1.6%	1.6%	1.6%

Decision Year	2016
Payback Criteria	4

Acct No.	Customer	Address	2016 Natural Gas Conversion Costs	Natural Gas O&M 2016	Natural Gas O&M 2017	Natural Gas O&M 2018	Natural Gas O&M 2019	Natural Gas Billing 2016	Natural Gas Billing 2017	Natural Gas Billing 2018	Natural Gas Billing 2019
	1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	3		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	4		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	5		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	6		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	7		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	8		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	10										
	11		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	12		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	13		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	14		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	15		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	16		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	17		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	18		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	19		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	20		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	21		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	22		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	23		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	24		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	25		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	26		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	27		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	28		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	29		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	30		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	31		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	32		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	33		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	34		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	35		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	36		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION HAS BEEN REDACTED

Decision Year	2016
Payback Criteria	4

Demand	$6.75/Dth	$6.75/Dth	$6.75/Dth	$6.75/Dth
Volumetric	$0.19/Dth	$0.19/Dth	$0.19/Dth	$0.19/Dth
GRSA	17%	17%	17%	17%
GCA	$5.18/Dth	$5.18/Dth	$5.18/Dth	$5.18/Dth
PSIA	$0.41/Dth	$0.41/Dth	$0.41/Dth	$0.41/Dth
DSMCA	1.6%	1.6%	1.6%	1.6%

Acct No.	Customer	Address	2016 Natural Gas Conversion Costs	Natural Gas O&M 2016	2017	Natural Gas O&M 2018	2019	2016	2017	2018	2019
	37		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	38		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	39		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	40		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	41		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	42		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	43		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	44		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	45		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	46		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	47		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	48		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	49		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	50		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	51		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	52		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	53		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	54		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	55		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	56		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	57		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	58		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	59		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	60		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	61		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	62		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	63		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	64		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	65		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	66		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	67		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	68		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	69		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	70		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	71		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	72		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	73		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	74		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	75		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Demand	$6.75/Dth	$6.75/Dth	$6.75/Dth	$6.75/Dth
Volumetric	$0.19/Dth	$0.19/Dth	$0.19/Dth	$0.19/Dth
GRSA	17%	17%	17%	17%
GCA	$5.18/Dth	$5.18/Dth	$5.18/Dth	$5.18/Dth
PSIA	$0.41/Dth	$0.41/Dth	$0.41/Dth	$0.41/Dth
DSMCA	1.6%	1.6%	1.6%	1.6%

Decision Year	2016
Payback Criteria	4

Acct No.	Customer	Address	2016 Natural Gas Conversion Costs	Natural Gas O&M 2016	2017	Natural Gas O&M 2018	2019	2016	2017	2018	2019
	76		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	77		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	78		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	79										
	80		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	81		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	82		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	83		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	84		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	85		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	86		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	87		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	88		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	89		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	90		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	91		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	92		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	93		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	94		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	95		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	96		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION HAS BEEN REDACTED

Demand	$6.75/Dth	$6.75/Dth	$6.75/Dth	$6.75/Dth
Volumetric	$0.19/Dth	$0.19/Dth	$0.19/Dth	$0.19/Dth
GRSA	17%	17%	17%	17%
GCA	$5.18/Dth	$5.18/Dth	$5.18/Dth	$5.18/Dth
PSIA	$0.41/Dth	$0.41/Dth	$0.41/Dth	$0.41/Dth
DSMCA	1.6%	1.6%	1.6%	1.6%

Decision Year	2016
Payback Criteria	4

Acct No.	Customer	Address	2016 Natural Gas Conversion Costs	Natural Gas O&M 2016	Natural Gas O&M 2017	Natural Gas O&M 2018	Natural Gas O&M 2019	2016	2017	2018	2019
	97		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	98		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	99		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	100		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	101		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	102		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	103		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	104										
	105		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	106		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	107		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	108		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	109		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	110		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	111		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	112		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	113		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	114		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	115		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	116		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	117		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	118		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	119		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	120										
	121										
	122										
	123		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	124		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	125		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	126										
	127		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	128		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	129		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	TOTAL YEAR		**$99,737,743**	**$1,838,958**	**$1,875,737**	**$1,913,252**	**$1,951,517**	**$7,443,887**	**$7,443,887**	**$7,443,887**	**$7,443,887**

CONFIDENTIAL INFORMATION HAS BEEN REDACTED

Decision Year	2016
Payback Criteria	4

Steam Billing		**Steam Billing**		**Steam Billing**
S&F	$200	$200	$200	$200
Demand	$40/Mlbs-mo	$40/Mlbs-mo	$40/Mlbs-mo	$40/Mlbs-mo
Volumetirc	$6.60/Mlbs	$6.60/Mlbs	$6.60/Mlbs	$6.60/Mlbs
GRSA	63%	63%	63%	63%
SCA	$8.84/Dth	$8.84/Dth	$8.84/Dth	$8.84/Dth

Acct No.	Customer	Address	2016	2017	2018	2019	Net Cost
	1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	3		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	4		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	5		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	6		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	7		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	8		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	10						
	11		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	12		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	13		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	14		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	15		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	16		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	17		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	18		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	19		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	20		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	21		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	22		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	23		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	24		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	25		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	26		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	27		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	28		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	29		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	30		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	31		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	32		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	33		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	34		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	35		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	36		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION HAS BEEN REDACTED

Decision Year	2016	
Payback Criteria	4	

	2016	2017	2018	2019
Steam Billing		**Steam Billing**		**Steam Billing**
S&F	$200	$200	$200	$200
Demand	$40/Mlbs-mo	$40/Mlbs-mo	$40/Mlbs-mo	$40/Mlbs-mo
Volumetirc	$6.60/Mlbs	$6.60/Mlbs	$6.60/Mlbs	$6.60/Mlbs
GRSA	63%	63%	63%	63%
SCA	$8.84/Dth	$8.84/Dth	$8.84/Dth	$8.84/Dth

Acct No.	Customer	Address	2016	2017	2018	2019	Net Cost
	37		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	38		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	39		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	40		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	41		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	42		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	43		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	44		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	45		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	46		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	47		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	48		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	49		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	50		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	51		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	52		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	53		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	54		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	55		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	56		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	57		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	58		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	59		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	60		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	61		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	62		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	63		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	64		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	65		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	66		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	67		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	68		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	69		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	70		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	71		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	72		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	73		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	74		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	75		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION HAS BEEN REDACTED

Decision Year	2016
Payback Criteria	4

Steam Billing		**Steam Billing**		**Steam Billing**
S&F	$200	$200	$200	$200
Demand	$40/Mlbs-mo	$40/Mlbs-mo	$40/Mlbs-mo	$40/Mlbs-mo
Volumetirc	$6.60/Mlbs	$6.60/Mlbs	$6.60/Mlbs	$6.60/Mlbs
GRSA	63%	63%	63%	63%
SCA	$8.84/Dth	$8.84/Dth	$8.84/Dth	$8.84/Dth

Acct No.	Customer	Address	2016	2017	2018	2019	Net Cost
	76		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	77		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	78		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	79						
	80		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	81		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	82		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	83		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	84		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	85		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	86		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	87		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	88		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	89		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	90		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	91		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	92		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	93		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	94		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	95		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	96		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION HAS BEEN REDACTED

Decision Year	2016
Payback Criteria	4

	Steam Billing	Steam Billing		Steam Billing
S&F	$200	$200	$200	$200
Demand	$40/Mlbs-mo	$40/Mlbs-mo	$40/Mlbs-mo	$40/Mlbs-mo
Volumetirc	$6.60/Mlbs	$6.60/Mlbs	$6.60/Mlbs	$6.60/Mlbs
GRSA	63%	63%	63%	63%
SCA	$8.84/Dth	$8.84/Dth	$8.84/Dth	$8.84/Dth

Acct No.	Customer	Address	2016	2017	2018	2019	Net Cost
	97		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	98		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	99		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	100		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	101		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	102		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	103		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	104						
	105		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	106		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	107		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	108		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	109		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	110		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	111		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	112		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	113		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	114		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	115		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	116		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	117		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	118		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	119		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	120						
	121						
	122						
	123		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	124		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	125		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	126						
	127		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	128		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	129		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	TOTAL YEAR		**$23,809,071**	**$23,809,071**	**$23,809,071**	**$23,809,071**	**$41,856,473**

CONFIDENTIAL INFORMATION HAS BEEN REDACTED

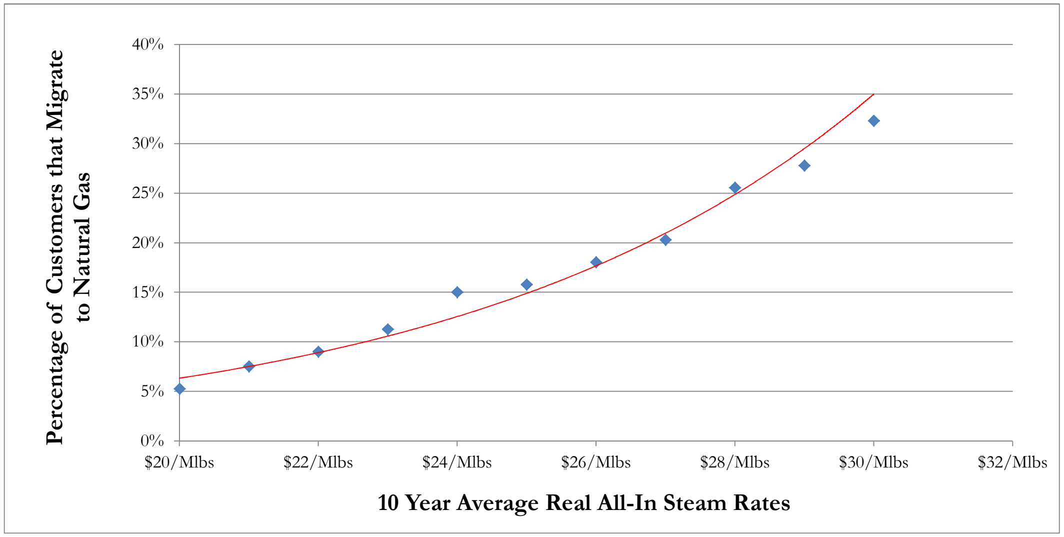
Customer Response to Changes in All In Rates

	2011 / 2012 Test Year
# of Customers	133
Design Day Peak	515 Mlbs
Billed Demand	106,313 Mlbs
Annual Volume	928,121 Mlbs

10 Year Average Real All-In Steam Rate	$20/Mlbs	$21/Mlbs	$22/Mlbs	$23/Mlbs	$24/Mlbs	$25/Mlbs	$26/Mlbs	$27/Mlbs	$28/Mlbs	$29/Mlbs	$30/Mlbs
# of Customer Expected To Conver to Natural Gas	7	10	12	15	20	21	24	27	34	37	43
Peak Load	18 Mlbs	26 Mlbs	29 Mlbs	33 Mlbs	49 Mlbs	52 Mlbs	60 Mlbs	74 Mlbs	93 Mlbs	110 Mlbs	126 Mlbs
Associated Billed Demand	3,795 Mlbs	6,786 Mlbs	7,701 Mlbs	8,786 Mlbs	12,515 Mlbs	13,061 Mlbs	14,809 Mlbs	20,022 Mlbs	24,453 Mlbs	28,065 Mlbs	31,323 Mlbs
Associated Annual Volume	67,466 Mlbs	96,749 Mlbs	107,608 Mlbs	122,105 Mlbs	171,660 Mlbs	179,012 Mlbs	204,751 Mlbs	247,482 Mlbs	294,159 Mlbs	348,709 Mlbs	380,259 Mlbs

Pecent Reductions

Customers Expected To Conver to Natural Gas	5.3%	7.5%	9.0%	11.3%	15.0%	15.8%	18.0%	20.3%	25.6%	27.8%	32.3%
Associated Peak Load	3.6%	5.0%	5.6%	6.4%	9.5%	10.1%	11.6%	14.4%	18.0%	21.4%	24.5%
Associated Billed Demand	3.6%	6.4%	7.2%	8.3%	11.8%	12.3%	13.9%	18.8%	23.0%	26.4%	29.5%
Associated Annual Volume	7.3%	10.4%	11.6%	13.2%	18.5%	19.3%	22.1%	26.7%	31.7%	37.6%	41.0%

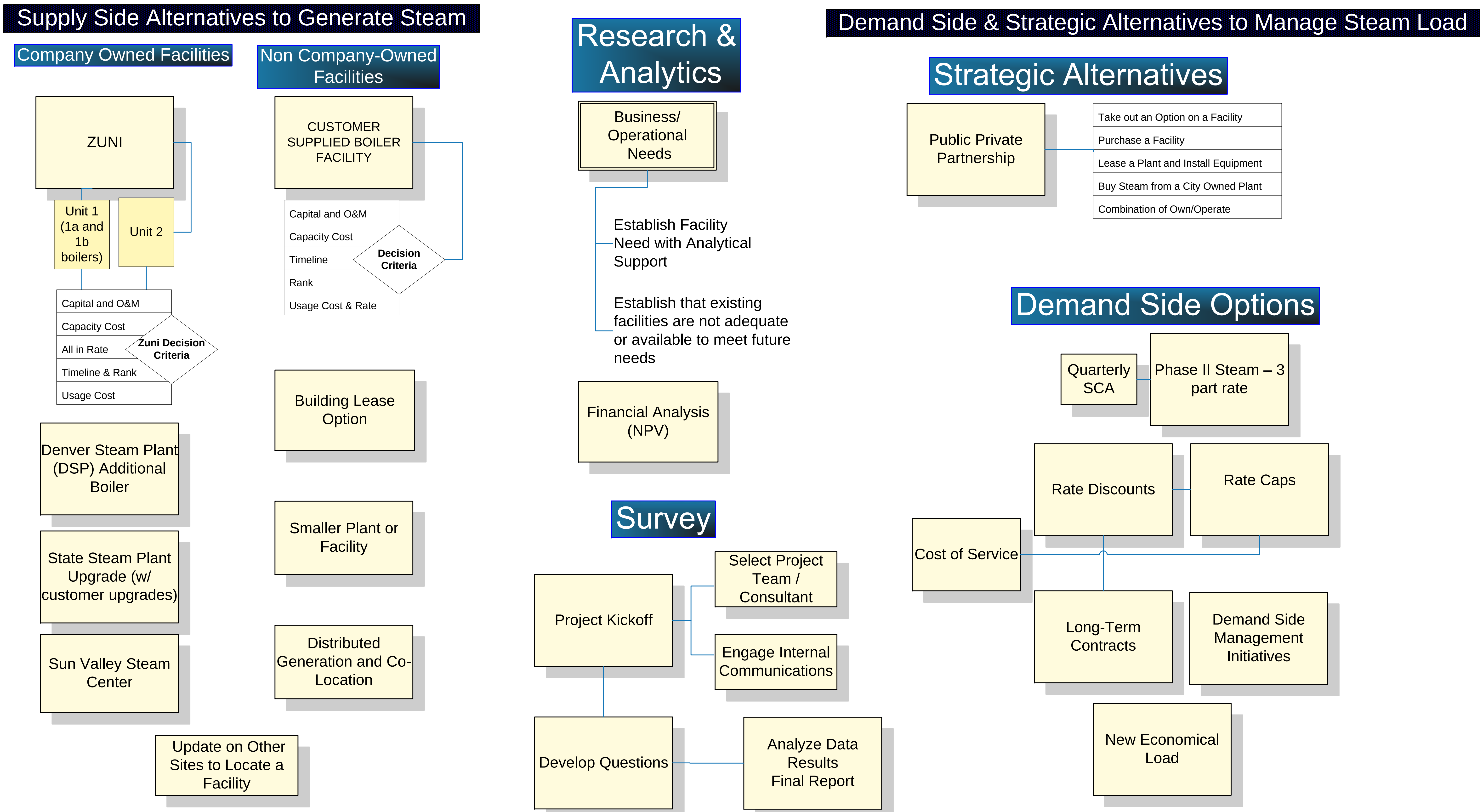


RESULTS OF NATIONAL SURVEYS AND AND XCEL ELECTRIC DSM STUDIES

Type of Research	Year of Research	# of Respondents or Projects	Average Payback (Years)
IBE National Survey (Johnson Controls)	2013	3392	3.4
IBE IFMA National Survey (Larger Facilities than Johnson Controls Survey)	2012	566	4.1
MN Custom C&I CIP Projects	2012	447	4.1
CO Customer C&I EE Projects	2012	423	4.1
Average			**3.9**

RESULTS OF PUBLIC SERVICE SURVEY OF STEAM CUSTOMERS

On average, decision - makers would typically target a payback period of about 4.3 years when considering the ROI to switch to a different heating system.


Supply Side Alternatives to Generate Steam
Company Owned Facilities
Non Company-Owned Facilities
ZUNI
Unit 1 (1a and 1b boilers)
Unit 2
Capital and O&M
Capacity Cost
All in Rate
Timeline & Rank
Usage Cost
Zuni Decision Criteria
Denver Steam Plant (DSP) Additional Boiler
State Steam Plant Upgrade (w/ customer upgrades)
Sun Valley Steam Center
Update on Other Sites to Locate a Facility
CUSTOMER SUPPLIED BOILER FACILITY
Capital and O&M
Capacity Cost
Timeline
Rank
Usage Cost & Rate
Decision Criteria
Building Lease Option
Smaller Plant or Facility
Distributed Generation and Co-Location
Research & Analytics
Business/ Operational Needs
Establish Facility Need with Analytical Support
Establish that existing facilities are not adequate or available to meet future needs
Financial Analysis (NPV)
Survey
Project Kickoff
Select Project Team / Consultant
Engage Internal Communications
Develop Questions
Analyze Data Results Final Report
Demand Side & Strategic Alternatives to Manage Steam Load
Strategic Alternatives
Public Private Partnership
Take out an Option on a Facility
Purchase a Facility
Lease a Plant and Install Equipment
Buy Steam from a City Owned Plant
Combination of Own/Operate
Demand Side Options
Quarterly SCA
Phase II Steam – 3 part rate
Rate Discounts
Rate Caps
Cost of Service
Long-Term Contracts
Demand Side Management Initiatives
New Economical Load