BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 390

In the Matter of	)
	)
Cascade Natural Gas Corporation	)
	)
Request for a General Rate Revision.	)
	)
	)

OPENING TESTIMONY OF LANCE D. KAUFMAN

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

July 30, 2020

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lance Kaufman. I am the principal economist of Aegis Insight. My qualifications are included in Exhibit AWEC/101.

Q. ON WHOSE BEHALF YOU ARE TESTIFYING?

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving gas sales and transportation services from Cascade Natural Gas Corporation ("Cascade" or "Company") in Oregon.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses cost allocations and plant investment. I also analyzed Cascade's long run incremental cost study and rate design issues for this case but the parties were able to negotiate a settlement in principle related to all cost of service, rate spread, and rate design issues. The parties have also filed a partial stipulation addressing and resolving cost of capital issues. Accordingly, I do not address cost of service or cost of capital issues in this testimony.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I make the following recommendations in my testimony:

1. Cascade's allocation of Montana-Dakota Utility Resources Group, Inc. ("MDUR") costs should be reduced by the ratio between the Utility Group's current Corporate Overhead allocation factor and a compound allocation factor that equally weights revenue, expense, employees, and capitalization. This

adjustment reduces Cascade's allocation of expenses by $2.8 million ($689,000 Oregon allocated).

2. The Commission should disallow a return on 10 percent of Cascade's 2019 capital projects. This reduces Oregon allocated rate base by $2.1 million.
3. Cascade should include the following analysis of do-nothing scenarios when evaluating system reinforcements of areas with peak day pressures above 15 psig:
   a. A Cost Benefit analysis;
   b. The identification of sources of growth, growth rates, and date when peak day distribution pressures are expected to fall below critical levels; and
   c. An evaluation of impacts of other planned projects on peak day pressures.
4. Cascade should not include future mains in rate base or depreciation expense.
5. Cascade should respond to Staff discovery related to future mains.

II. COST ALLOCATION

Q. PLEASE SUMMARIZE THIS ISSUE.

A. Cascade operates as a subsidiary of MDUR. The MDUR organization chart identifies 80 subsidiaries with operations spanning a variety of enterprises including energy, construction, insurance, and finance.[1] MDUR's non-utility operations cover every state in the United States, excluding New England and Rhode Island.[2] Despite the fact that MDUR's non-utility operations have a much broader geographic scope, many times more employees and greater revenues and expenses than the utility operations, the utility

[1] AWEC/102 Kaufman/36 Response to AWEC DR 24
[2] MDUR 2019 Annual Report page 3.

operations receive the majority of allocated costs. On its face, this appears to be unreasonable.

MDUR allocates costs among subsidiaries according to its cost allocation manual. These costs are disproportionately allocated to utility subsidiaries. For example, the general corporate allocator is based on a single measure: share of capitalization. Other potential allocators are share of revenue, expense, or employees. Many utilities allocate general costs using a compound allocation factor that includes several cost drivers. MDUR's utility group's share of capitalization is 60 percent, while its share of revenue, expense, and employees is 23, 22, and 12 percent, respectively.[3]

I recommend that Cascade's allocation of costs from MDUR be reduced by $2.8 million ($689,000 Oregon allocated).

Q. WHAT GENERAL PRINCIPLES DO YOU SUPPORT WHEN MAKING COST ALLOCATIONS?

A. I support using the National Association of Regulatory Utility Commissioners' "Guidelines for Cost Allocations and Affiliate Transactions." These guidelines are provided in Exhibit AWEC 103.

Q. HOW HAVE CASCADE'S ALLOCATION OF COSTS CHANGED IN THE LAST THREE YEARS?

A. Cascade's allocation of costs increased from $16.7 million in 2017 to $24.1 million in 2019, which equates to a 44 percent increase over two years.

Q. WHAT CONCERNS DO YOU HAVE RELATED TO COST ALLOCATIONS?

A. I have the following concerns:

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[3] MDUR 2019 Annual Report

1. The MDUR corporate allocator does not reflect revenues, expenses, or employees as drivers of general costs.
2. Certain account specific allocators include components that only allocate costs to utilities.
3. The allocations and affiliate transactions are not transparent.

Q. WHAT IS THE MDUR CORPORATE OVERHEAD ALLOCATOR?

A. The MDUR corporate overhead allocator is presented on Page 32 of the MDUR cost allocation manual. The factor is calculated as the share of capitalization. The utility group is allocated 59.3 percent of costs using this factor. There is no direct relationship between corporate overhead and capitalization. At best, capitalization is a generic proxy for support provided by MDUR to subsidiaries. The overhead allocator fails to account for other important drivers of MDUR overhead costs.

Q. WHY ARE GENERIC PROXIES REASONABLE FOR ALLOCATING OVERHEAD?

A. Many costs are general costs that do not directly support business functions, but are necessary and incurred through the normal course of business. From a shareholder perspective, these costs are necessary to ensure profitable operations and provide a return to investors. Return is calculated as revenue, less expenses, divided by investment. General business operations support a return on investment by appropriately managing revenues, expenses, and investment. As such, revenues, expenses, and investment (or capitalization) are appropriate general proxies for overhead cost drivers. Management and support of employees is another critical function of corporations.

Q. WHAT IS THE UTILITY GROUP'S SHARE OF REVENUE, EXPENSE, EMPLOYMENT, AND CAPITALIZATION?

A. The table below summarizes the Utility Group's share of each of these measures. The Utility Group's share of the capitalization measure is three times larger than the other measures.

Table 1: Utility Share of Cost Proxy Values

	Value			Share	
	Utility	**Non-utility**	**Total**	**Utility**	**Non-utility**
Revenue (millions)	$1,217	$4,180	$5,397	23%	77%
Expense (millions)	$1,123	$3,937	$5,060	22%	78%
Employees	1,584	11,775	13,359	12%	88%
Equity (millions)	$2,479	$1,699	$4,178	59%	41%
Average				29%	71%

Q. WHAT OTHER ACCOUNT SPECIFIC ALLOCATORS ARE YOU CONCERNED WITH?

A. Several MDUR accounts are allocated using more specific allocators. Many of these allocators, however, don't include non-utility components. For example:

1. 766 Time Entry Shared Services names a construction services Desert Fire, a subsidiary of Construction Services Group, but Construction Services Group receives no allocation of these costs.
2. 762 Business Services is based on an average including the three accounts that follow, and suffer from the same issues.
3. 763 Fleet and Travel uses a compound factor that includes a number of managed units, but no managed units are counted for non-regulated subsidiaries.
4. 764 Supply Chain uses a compound factor with no allocation to non-regulated subsidiaries.

5. 767 Accounts Payable uses a compound factor with eighty percent of the weight on items that allocate no costs to non-regulated subsidiaries.
6. 965 Customer Operations only directly charges utility subsidiaries, and includes direct charges in a compound allocation factor.
7. 971 Communications only directly charges utility subsidiaries and includes direct charges in a compound allocation factor.
8. 972 Operations only directly charges regulated subsidiaries and includes direct charges in a compound allocation factor.
9. 982 Governance is a compound factor that includes the three previous accounts and is subject to the same concerns.[4]

The issues identified above demonstrate a systematic pattern of allocating costs in a manner that shifts costs to regulated subsidiaries in favor of unregulated subsidiaries. This provides a windfall to shareholders at the expense of ratepayers.

Q. WHY DO YOU CONSIDER CASCADE'S ALLOCATIONS AND AFFILIATE TRANSACTIONS TO BE NON-TRANSPARENT?

A. Cascade was asked to identify company and subsidiary allocated costs and the allocation of such costs. Cascade was also asked to identify the Commission filing approving affiliate transactions. Cascade failed to identify the total subsidiary amounts for allocated costs, the allocation factors used to allocate these costs, or the Commission filing approving affiliate transactions.

[4] AWEC/102 Kaufman/39 Response to AWEC DR 24.

Q. WHAT IS YOUR RECOMMENDATION FOR THIS ISSUE?

A. I recommend that Cascade's allocation of MDUR costs be reduced by the ratio between the Utility Group's current Corporate Overhead allocation factor and a compound allocation factor that equally weights revenue, expense, employees, and capitalization. This recommendation reduces Cascade's allocation of expenses by $2.8 million ($689,000 Oregon allocated).

III. PLANT INVESTMENT

Q. WHAT ISSUES DO YOU RAISE RELATED TO CASCADE'S PLANT INVESTMENT?

A. I identified three issues related to Cascade's plant investment:

1. Insufficient budgeting and management documentation;
2. Growth based investment unsupported by growth forecasts; and
3. Unused plant included in base rates.

a. Insufficient Budgeting and Management Documentation

Q. PLEASE SUMMARIZE THIS ISSUE.

A. Cascade invested $20.6 million in capital projects in 2019.[5] Cascade, however, retained no budgeting or project management documentation for this capital spend other than a single project proposal for the Umatilla Reinforcement.[6] The Commission cannot make a determination regarding whether an investment decision was prudent, or whether the management of the project was prudent, if there is no documentation of the investment decision or the management of the project. Cascade should bear the burden of documenting its decisions and actions related to capital investment. I recommend the

[5] AWEC/102 Kaufman/20 Response to AWEC DR 4.
[6] AWEC/102 Kaufman/14 and 34 Response to AWEC DR 3 and DR 21.

Commission disallow a return on 10 percent of Cascade's 2019 capital projects. This reduces Oregon allocated rate base by $2.1 million.

Q. DOES CASCADE FOLLOW A DISTRIBUTION PLANNING PROCESS?

A. Cascade claims to follow a distribution planning process that incorporates forecasted growth, costs, benefits, and feasibility of alternatives. However, Cascade provides no documentation of any stage of this analysis, offering only the project proposal of selected projects as documentation of the planning process.[7]

Q. PLEASE EXPLAIN WHY CASCADE SHOULD MAINTAIN BUDGETING AND PROJECT MANAGEMENT DOCUMENTS.

A. Cascade's customers should only pay for prudently incurred costs. Without proper documentation of why Cascade chose to make an investment, the basis for the original budget, project changes and budget changes, and actual expenditures, the Commission and stakeholders are unable to reasonably evaluate whether capital costs were prudently incurred. For example, in 2019 Cascade budgeted $3.2 million for Oregon service and main growth.[8] The actual amount spent was $6.7 million—more than twice the budgeted amount.[9] Cascade provided no documentation for how the original budget was developed, when or why the budget changed, or what the dollars were spent on. Without this information, the Commission cannot determine if the initial budget was appropriate, whether Cascade managed or controlled costs throughout the year, or whether the final amount transferred to plant included any items not appropriately included in rates such as penalties, incentives or excessive affiliate transactions.

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7 AWEC/102 Kaufman/2 Response to AWEC DR 2.
8 AWEC/102 Kaufman/20 Response to AWEC DR 4.
9 AWEC/102 Kaufman/20 Response to AWEC DR 4.

Q. HOW HAS THE COMMISSION HISTORICALLY TREATED CAPITAL INVESTMENT WITH INSUFFICIENT DOCUMENTATION?

A. In a case involving NW Natural, the Commission held that it could not conclude that costs were prudently incurred because the utility failed to meet its burden of proof.[10] NW Natural had argued that the Mid-Willamette Valley Feeder was needed to meet growth in 2025 and that the project was justified on reliability grounds.[11] The Commission determined that NW natural "failed […] to provide any evidentiary support for these assertions."[12] The Commission commented that:

> *Simply having a witness testify, in conclusory fashion, that all other options were inferior, is not adequate to justify a major investment. Nor is it sufficient to simply state that the timing for expansion was right given the replacement of bare steel pipes on other segments, without any quantification of the perceived benefits or any comparison to alternatives.*[13]

Additionally, the Commission determined that "nothing in the record supports the company's assertion."[14] Therefore, the Commission denied recovery of costs associated with the Mid-Willamette Valley Feeder, stating that NW Natural "failed to provide evidence of unreliability or the type of quantitative analysis or resource comparison that would allow us to conclude, based on the record evidence, that the project was prudent."[15] The Commission stated that "all major pipeline investments should go through a rigorous IRP review."[16] The Commission also stated that although "a company need not include a project in an IRP to seek its recovery in rates," the Commission will "give considerable weight to utility actions which are consistent with acknowledged IRPs

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[10] *In the Matter of NW. Nat. Gas Co.*, Order No. 12-437 at 16 (Or PUC Nov 16, 2012).
[11] *Id.* at 13-16.
[12] *Id.* at 16.
[13] *Id.* at 17 n. 43.
[14] *Id.* at 17.
[15] *Id.*
[16] *Id.* at 17 n. 44.

and require explanations for actions that are inconsistent with an IRP."[17] Additionally, "when a company is seeking ratemaking treatment of a significant project that has not been included in an IRP, we will hold the company to the same level of rigorous review required by the IRP to demonstrate the prudence of the project."[18]

Q. DID CASCADE MEET THE STANDARD FOR APPROVAL OF ITS CAPITAL PROJECTS DESCRIBED IN ORDER NO. 12-437?

A. Based on my review of Cascade's filing and responses to data requests, I do not believe Cascade has met its burden of proof for its capital project program.

Q. WHAT IS YOUR RECOMMENDATION FOR THIS ISSUE?

A. I recommend the Commission disallow a return on 10 percent of Cascade's 2019 capital projects. This reduces Oregon allocated rate base by $2.1 million.

b. Distribution Investment Unsupported by Forecasts

Q. PLEASE SUMMARIZE THIS ISSUE.

A. Cascade supports investments in distribution mains based on the results of distribution pressure modeling. This modeling is performed under peak weather conditions and at Cascade's current customer load.[19] Cascade uses a threshold pressure of 20 psig to identify distribution reinforcement needs.[20] Other gas distribution companies, such as Northwest Natural Gas Company, use a lower threshold of 10 psig.[21] Cascade supports the use of a high threshold based on assumed growth and the risk that design and construction delays combined with assumed growth will result in system outages.[22]

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17 *Id.* at 17-18 n. 44.
18 *Id.* at 18 n. 44.
19 AWEC/102 Kaufman/27 Response to AWEC DR 12 part d.
20 AWEC/102 Kaufman/25 Response to AWEC DR 9
21 OPUC Docket UG 344, NW Natural/800, Karney/Page 27 lines 14 to 16.
22 AWEC/102 Kaufman/25 Response to AWEC DR 9

Cascade, however, does not model the impact of forecasted regional growth on distribution pressures. This absence of growth modeling could result in earlier than necessary investment. The Commission has previously found investing in distribution mains ahead of need to be imprudent.[23]

Q. IS THERE A SPECIFIC INVESTMENT THAT ILLUSTRATES YOUR CONCERN?

A. Yes. Cascade is requesting approval of investment in the Ponderosa Reinforcement Project.[24] Cascade's pressure modeling demonstrates that the areas affected by the project are above 15 psig, but below 20 psig. Satellite imagery of the reinforced area (Figure 3 below) shows no available land for new development,[25] indicating any local growth will require gas conversion.

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[23] In matter of NW Natural GAS Company, Order No. 12-437 (Or PUC Nov 16, 2012), the Commission held that a project needed to serve load growth thirteen years in the future was not prudent and, therefore, not includable in rate base. NW Natural sought to include two phases of the Mid-Willamette Valley Feeder in its rate base. NW Natural conceded that the project was not needed to meet incremental load growth until after 2020 and was included in the IRP to serve incremental load growth in 2025. Because NW natural "failed to demonstrate that the costs of these projects are prudent at this time," the Commission concluded "that the project is not justified at this time on grounds that it is needed to meet load." The Commission noted, however, that its determination "is based on the company's assertion that the project is currently needed for reliability purposes. If facts change, if, for example, the incremental loads in the area start growing faster, and the company makes an evidence-based showing of need, we would be willing to consider the depreciated costs of the project for inclusion in rates on an alternative basis."

[24] CNGC/200 Darras/20.

[25] The open space in the north of the image does not appear to be available for development.

Figure 1: Before Reinforcement

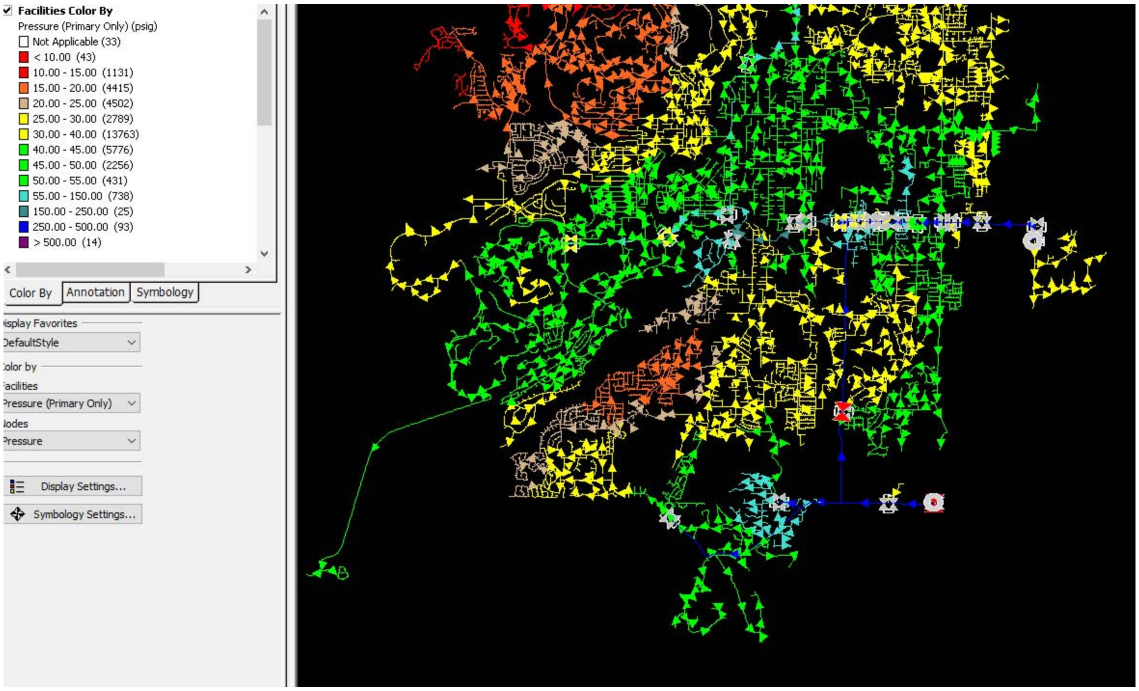


Figure 2: After Reinforcement

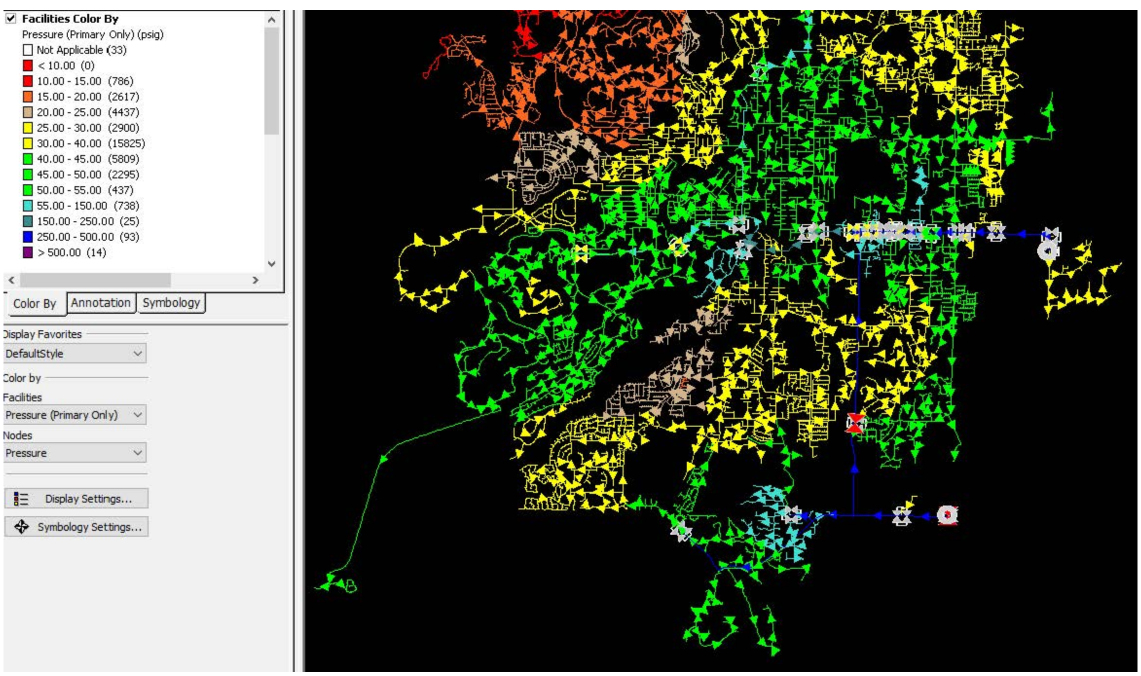
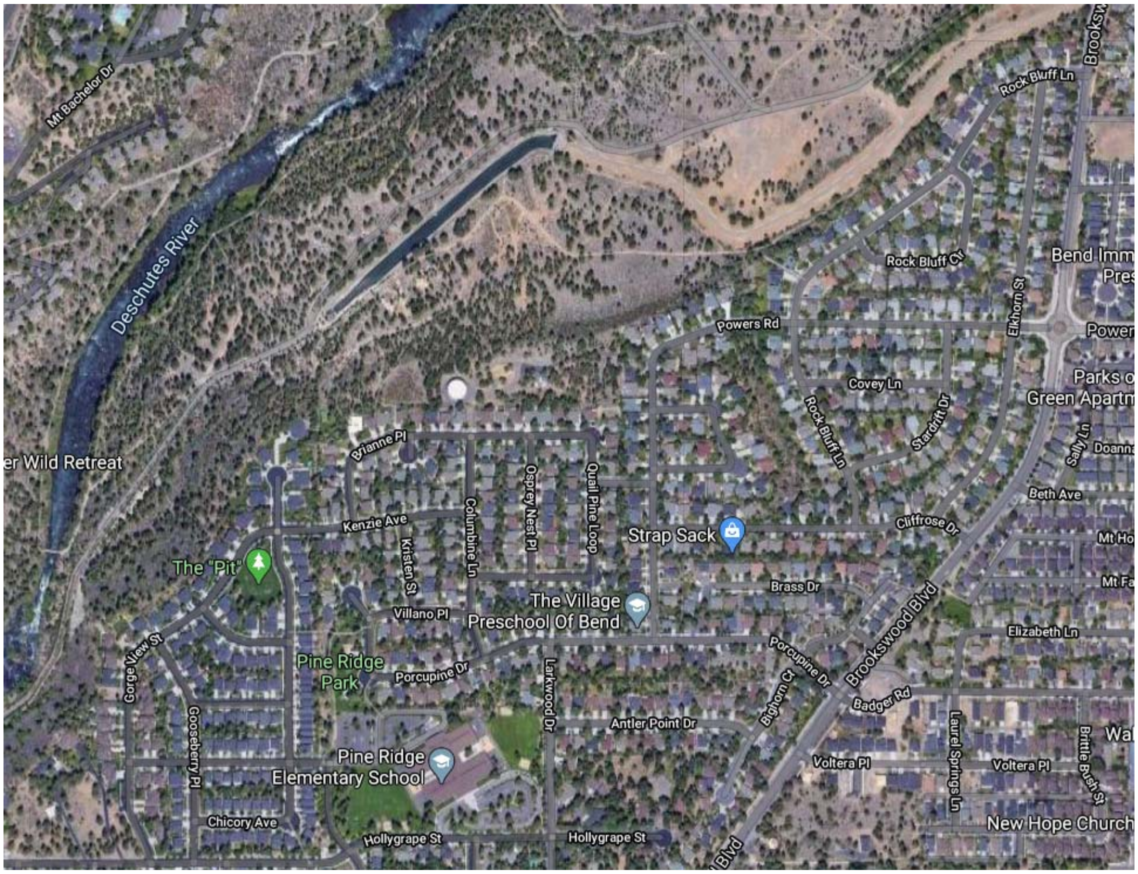


Figure 3: Reinforced Area



Q. DID CASCADE PROVIDE A COST BENEFIT ANALYSIS FOR THIS REINFORCEMENT?

A. No. Cascade notes that no reinforcement is an option, but did not provide the expected costs of the do-nothing option.

Q. DID CASCADE'S MODELING REFLECT THE CUMULATIVE IMPACT OF BEND'S ONGOING DISTRIBUTION REINFORCEMENT PROJECTS?

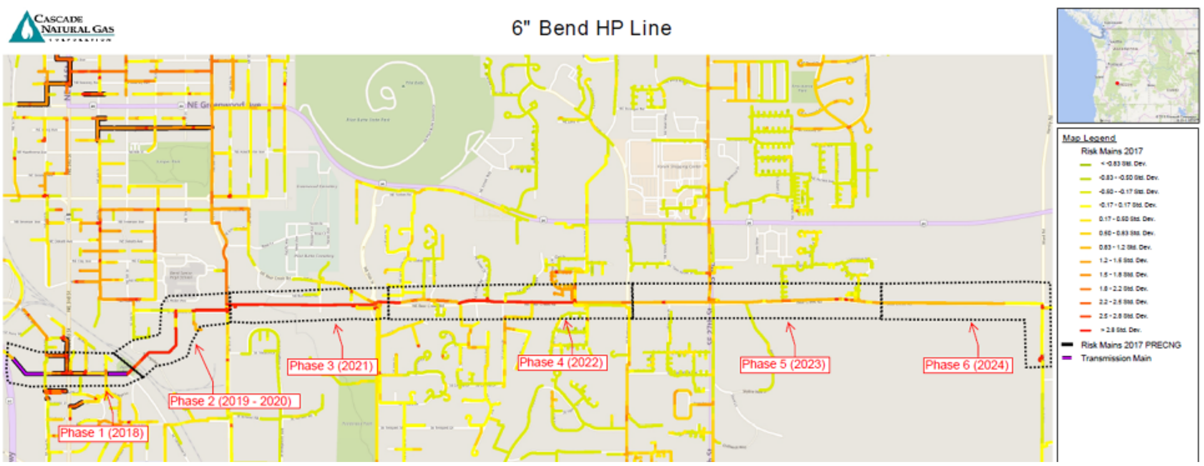
A. No. Cascade supports this investment with a one-off comparison of the current system to the Pondarosa reinforced system, without accounting for other ongoing Bend reinforcements. Cascade's 2020 IRP identifies six distribution projects in Bend.[26]

[26] Cascade 2020 Draft IRP Page 1-12.

Other Bend reinforcements could sufficiently increase Bend pressures to mitigate the relatively minor pressure issues with this area.

Q. ARE THERE OTHER EXAMPLES OF DISTRIBUTION INVESTMENTS THAT ARE NOT SUPPORTED?

A. Yes. Cascade is in the middle of a six-phase main replacement project in Bend driven by safety risk associated with insufficient cover.[27] As part of this project Cascade is increasing the pipe size to 12 inches.



Cascade's decision to replace the 6-inch pipe with a 12-inch pipe is not supported by analysis of the impact on Cascade's distribution system. Cascade's analysis is focused on the pressure at end point regulators. Cascade does not appear to have considered alternate designs, such as 8- or 10-inch pipe, or stepping down the pipe as the main approaches the city center.

In response to discovery requests Cascade has shown that a 12-inch pipe results in higher pressures at certain regulators than a 6-inch or 8-inch pipe. However, Cascade failed to demonstrate that the incremental pressure provides a benefit to Bend's distribution system. I requested Cascade provide more granular distribution pressures to

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[27] CNGC/200, Darras/12.

evaluate the impact of a 6- or 8-inch replacement on pressures at customer meters, however, Cascade did not provide the information.[28]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THIS ISSUE?

A. I recommend that Cascade include the following analysis of do-nothing scenarios when evaluating system reinforcements of areas with peak day pressures above 15 psig:

1. A cost benefit analysis;
2. Identification of sources of growth, growth rates, and date when peak day distribution pressures are expected to fall below critical levels; and
3. An evaluation of the impact of other planned projects on peak day pressures.

c. Unused Plant in Rate Base

Q. PLEASE SUMMARIZE THIS ISSUE.

A. Cascade states in testimony that it installed 4000 feet of "future main". This main was 6-inch pipe, capped at both ends, and filled with nitrogen. Cascade plans to connect the pipe to its system in the future. Cascade's testimony is unclear regarding whether the future main has already been transferred to plant or included in rate base. Cascade declined to respond to both Staff and AWEC discovery regarding this issue, indicating that the plant will be removed from rates.[29] However, the rational for removing the plant from rates was due to other project delays. Cascade states the asset has transferred to plant in 2016 but that it is not included in rate base.[30] I was not able to identify any proforma adjustments removing the asset from rate base or from depreciation expense.

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[28] AWEC/102 Kaufman/29 Response to AWEC DR 19.
[29] AWEC/102 Kaufman/24 and 76 Response to AWEC DR 8 and Staff DR 204.
[30] AWEC/102 Kaufman/35 Response to AWEC DR 22.

Q. WHAT IS YOUR RECOMMENDATION FOR THIS ISSUE?

A. I recommend that Cascade not include future mains in rate base or depreciation expense. I also recommend that Cascade respond to Staff discovery related to future mains.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS RELATED TO PLANT.

A. I made the following recommendations in this section:

1. The Commission should disallow a return on 10 percent of Cascade's 2019 capital projects. This reduces Oregon allocated rate base by $2.1 million.
2. Cascade should include the following analysis of do-nothing scenarios when evaluating system reinforcements of areas with peak day pressures above 15 psig:
    a. A cost benefit analysis;
    b. Identification of sources of growth, growth rates, and date when peak day distribution pressures are expected to fall below critical levels; and
    c. An evaluation of impacts of other planned projects on peak day pressures.
3. Cascade should not include future mains in rate base.
4. Cascade should respond to Staff discovery related to future mains.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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EXHIBIT AWEC/101

July 30, 2020

CURRICULUM VITAE

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EDUCATION:

University of Oregon	Ph.D.	Economics	2008 – 2013
University of Oregon	M.S.	Economics	2006 – 2008
University of Anchorage Alaska	B.B.A.	Economics	2001 – 2004

CERTIFICATIONS:

Certified Depreciation Professional	Society of Depreciation Professionals	2018

PROFESSIONAL EXPERIENCE:

Principal Economist	Aegis Insight	2014 – Present
Senior Economist	Oregon Public Utility Commission	2015 – 2018
Public Utility Advocate	Alaska Department of Law	2014 – 2015
Senior Economist	Oregon Public Utility Commission	2013 – 2014
Instructor	University of Oregon	2008 – 2012
Research Assistant	University of Alaska Anchorage	2003 – 2008

PROFESSIONAL MEMBERSHIPS:

Society of Depreciation Professionals	2015 – Present
American Economics Association	2017 – Present

RESEARCH, CONSULTING, AND ECONOMETRIC ANALYSIS:

- Jester, Gibson & Moore, Denver, CO 2019
  Retained as an expert witness for plaintiffs regarding lost earnings in an ADEA wrongful termination matter.
- Albrechta & Coble, Ltd. Fremont, OH 2019
  Retained as an expert witness for plaintiff regarding lost earnings in a race related wrongful termination matter.
- Conrad Law, PC, Salt Lake City, UT 2019
  Retained as an expert witness for Ellis-Hall Consultants, LLC. regarding economic damages in Ellis-Hall Consultants, LLC. et. al. v. George B. Hofmann IV, United States District Court, District of Utah, Central Division.
- Davison Van Cleve, PC, Salem, OR 2019
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net variable power cost calculations in PORTLAND GENERAL ELECTRIC COMPANY, 2020 Annual Power Cost Update Tariff Public Utility Commission of Oregon Docket No. UE 359.

- Sanger Law, PC, Salem, OR, 2019
  Testified as an expert witness for Renewable Energy Coalition and Rocky Mountain Coalition for Renewable Energy regarding Qualified Facility avoided costs in Application of Rocky Mountain Power for a Modification of Avoided Cost Methodology and Reduced Term of PURPA Power Purchase Agreements Public Service Commission of Wyoming Docket No. 20000-545-ET-18
- Sanger Law, PC, Salem, OR, 2019
  Retained to provide analysis of Portland General Electric wind production costs in support of the Northwest & Intermountain Power Producers Coalition comments in Oregon HB 2857.
- Sanger Law, PC, Salem, OR, 2019
  Retained as an expert witness for Cafeto Coffee Company regarding the necessity, design, and location of transmission lines in SPRINGFIELD UTILITY BOARD Petition for Certificate of Public Convenience and Necessity Public Utility Commission of Oregon Docket No. PCN 3.
- King & Greisen, LLP, Denver, CO 2018 –
  Provided statistical analysis of age disparity in re Raymond et. al. v. Spirit Aerosystems, Inc. Civil Action No. 6:16-cv-01282-EFM-GEB.
- Baumgartner Law, LLC, Denver, CO, 2018 – 2019
  Retained as an expert witness for plaintiffs re calculation of economic harm due to injury in re <u>Eric Bowman, v. Top Tier Colorado, LLC,</u>, Case No. 18CV31359, United States District Court, District of Colorado.
- Cohen Milstein Sellers & Toll PLLC, Washington DC, 2018 –
  Retained as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re <u>Isaac Harris et al. v. Medical Transportation Management, Inc.</u>, Civil Action No. 17-1371, United States District Court, District of Columbia.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2018 –
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re <u>Vicky Maldonado and Carter v. Apple Inc., AppleCare Services Company, Inc., and Apple CSC, Inc.</u>, Case No. 3:16-cv-04067-WHO, United States District Court, District of California.
- Hagens Berman Sobol Shapiro, LLP, Phoenix, Arizona, 2018 –
  Deposed and testified as an expert witness for plaintiffs re calculation of unpaid mileage for truck drivers in re <u>Swift Transportation Co., Inc.</u>, Civil Action No. CV2004-001777, Superior Court of the State of Arizona, County of Maricopa.
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2018
  Retained as expert witness for plaintiffs re reasonable attorney fees in re <u>Jeanne Stroup and Ruben Lee, v. United Airlines, Inc.</u>, Case No. 15-cv-01389-WYD-STV, United States District Court, District of Colorado.
- Klein and Frank, PC, Denver, Colorado, 2018
  Retained as expert witness for plaintiffs re potential jury bias in re <u>Gail Goehrig and Chris Goehrig v. Core Mountain Enterprises, LLC</u>, Case No. 2016CV030004, San Juan County District Court.
- Robert Belluso, Pennsylvania, 2017

Retained as expert witness for plaintiff re lost profit in re Robert Belluso D.O. v Trustees of Charleroi Community Park, PHRC Case No. 201505365, Pennsylvania Human Relations Commission.

- Lowery Parady, LLC, Denver, Colorado, 2017
  Analyzed payroll data and calculated unpaid overtime and unpaid hours for plaintiff class action in re Violeta Solis, et al. v. The Circle Group, LLC, et al., Case No. 1:16-cv-01329-RBJ, United States District Court, District of Colorado.
- Sawaya & Miller Law Firm, Denver, Colorado, 2017
  Provided data processing and analysis of employment records.
- Financial Scholars Group, Orinda, California, 2017
  Provided analysis of risk profile in bundled real estate and personal loans in re Old Republic Insurance Company v. Countrywide Bank et al., Circuit Court of Cook County, Illinois, Chancery Division.
- Financial Scholars Group, Orinda, California, 2017
  Provided consultation and analysis of financial market transactions in preparation of settlement claims filings in re Laydon v. Mizuho Bank, Ltd., et al. and Sonterra Capital Master Fund Ltd., et al v. UBS AG et al.
- Clean Energy Action, Boulder, Colorado, 2016 – 2017
  Provided consultation on the appropriate discounting methodology used in energy resource planning in the Public Service Company of Colorado application for approval of the 2016 Electric Resource Plan, Proceeding No. 16A-0396E, Public Utilities Commission of the State of Colorado.
- Confidential Client, 2016
  Provided analysis and report on the probability that distinct crimes are independent events based on geographical analysis of crime rates.
- Christine Lamb and Kevin James Burns, Denver, Colorado, 2016
  Provided data analysis for defendant of the impact of ethnicity on termination decisions in re Aragon et al v. Home Depot USA, Inc., Case No. 1:15-cv- 00466-MCA-KK, United States District Court, District of New Mexico.
- Steptoe & Johnson LLP, Washington, DC, 2015 – 2016
  Programmed analysis of internet traffic data for plaintiffs applying a proprietary probability model developed to identify and verify accounts responsible for repeated infringements of asserted copyrights by defendants' internet subscribers in re BMG Rights Management (US) LLC, and Round Hill Music LP v. Cox Enterprises, Inc., et al., Case No. 1:14-cv-1611(LOG/JFA), United States District Court Eastern District of Virginia, Alexandria Division.
- Hagens Berman Sobol Shapiro, LLP, Phoenix, Arizona, 2014 –
  Programmed analysis for plaintiffs to calculate unpaid mileage for truck drivers in re Swift Transportation Co., Inc., Civil Action No. CV2004-001777, Superior Court of the State of Arizona, County of Maricopa.
- Padilla & Padilla, PLLC, Denver, Colorado, 2014 – 2016
  Provided research and analysis for plaintiffs re the impact on minority applicants from use of the AccuPlacer Test by the City and County of Denver, and estimated damages in re Marian G. Kerner et al. v. City and County of Denver, Civil Action No. 11-cv-00256-MSK-KMT, United States District Court, District of Colorado.

- U.S. Equal Employment Opportunity Commission, 2013 –
  Provided statistical analysis of EEOC filings.

REGULATORY PROCEEDINGS:

- Portland General Electric 2016 Annual Power Cost Variance Docket No. UE 329.
- PacifiCorp 2016 Power Cost Adjustment Mechanism Docket No. UE 327.
- Public Utility Commission of Oregon Staff Investigation into the Treatment of New Facility Direct Access Charges Docket No. UM 1837
- PacifiCorp Oregon Specific Cost Allocation Investigation Docket No. UM 1824.
- PacifiCorp 2018 Transition Adjustment Mechanism Docket No. UE 323.
- Portland General Electric 2018 General Rate Case Docket No. UE 319.
- Avista Corp. 2017 General Rate Case Docket No. UG 325.
- Portland General Electric Affiliated Interest Agreement with Portland General Gas Supply Docket No. UI 376.
- Portland General Electric 2017 Automated Update Tariff Docket No. UE 308
- PacifiCorp 2017 Transition Adjustment Mechanism Docket No. UE 307
- Portland General Electric 2017 Reauthorization of Decoupling Adjustment Docket No. UE 306
- Northwest Natural Gas Investigation of WARM Program Docket No. UM 1750.
- PacifiCorp Investigation into Multi-Jurisdictional Allocation Issues Docket No. UM 1050.
- Idaho Power Company 2015 Power Supply Expense True Up Docket No. UE 305
- Homer Electric Association 2015 Depreciation Study U-15-094
- Submitted prefiled testimony regarding the depreciation study.
- Chugach Electric Association 2015 Rate Case U-15-081
- Developed staff position regarding margin calculations.
- ENSTAR 2014 Rate Case U-14-111
- Submitted prefiled testimony regarding sales forecast.
- Alaska Pacific Environmental Services 2014 Rate Case U-14-114/115/116/117/118
  Submitted prefiled testimony regarding cost allocations, cost of service, cost of capital, affiliated interests, and depreciation.
- Alaska Waste 2014 Rate Case U-14-104/105/106/107
  Submitted prefiled testimony regarding cost of service study, cost of capital, operating ratio, and affiliated interest real estate contracts.
- Fairbanks Natural Gas 2014 Rate Case U-14-102
  Submitted prefiled testimony regarding cost of service study and forecasting models.
- Avista 2015 Rate Case U-14-104
  Submitted analysis supporting OPUC Staff settlement positions regarding Avista's sales and load forecast, decoupling mechanisms and interstate cost allocation methodology. Represented Staff in settlement conferences on November 21, November 26, and December 4, 2013.
- Portland General Electric 2015 Rate Case
  Submitted pre-filed opening testimony addressing PGE's sales forecast, printing and mailing budget forecast, mailing budget, marginal cost study, line extension policy and reactive demand charge. Represented OPUC Staff in settlement conferences on May 20, May 27, and June 12, 2014.

- Portland General Electric 2014 General Rate Case
  Submitted analysis supporting OPUC Staff settlement positions regarding PGE's sales and load forecast, revenue decoupling mechanism, and cost of service study. Represented OPUC Staff in settlement conferences on May 29, June 3, June 6, July 2, and July 9 of 2013. Submitted testimony in support of partial stipulation, pre-filed opening testimony addressing PGE's decoupling mechanism, and testimony in support of a second partial stipulation.
- PacifiCorp 2014 General Electric Rate Case
  Submitted analysis supporting OPUC Staff settlement positions regarding PacifiCorp's sales and load forecast and cost of service study. Represented Staff in settlement conferences on June 12 through June 14, 2013.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 390

In the Matter of	)
	)
Cascade Natural Gas Corporation	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/102

July 30, 2020

Cascade Discovery Responses

AWEC DATA REQUEST NO. 2

Date prepared: June 30, 2020

Preparer: Linda Offerdahl

Contact: Christopher Mickelson

Telephone: (509)-734-4549

AWEC DR 2 TO CASCADE:

Please refer to CNGC/200, Darras/6, figure 1. Please provide documentation supporting each phase of distribution planning identified on this figure for each distribution enhancement project in 2019 and 2020. Please include assumptions and dates for any Synergi models.

Response:

The first few steps of information gathering, models of the system limitations, and identifying potential projects are all captured in the project executive summaries. See attached exhibits AWEC-2A, AWEC-2B, and AWEC-2C.pdf for the 2019 and 2020 project executive summaries. The remaining steps shown in Darras/6, figure 1 (rank projects and schedule into budget) typically occur through multiple meetings throughout the company.

Project Summary – Umatilla Reinforcement – WO 261315

Submitted by: Linda Offerdahl
10/5/2018

Background

The system between the Umatilla River and I-82 is a single feed. Connecting this system to the North Hermiston system would allow for isolation and necessary maintenance, repair, and replacement of aging facilities in the town of Umatilla.

The route was chosen by minimizing distance, ease of construction, and ability to obtain easements and permits, with these criteria, the route still includes several conflicts with other underground utilities, a canal crossing, and two highway crossings.

The project site starts at Highway 395 and heads west on Highway 730 just past the I-82 overpass. The location is shown on the map below:

Proposal

This project consists of installing approximately 650 feet of 4-inch steel HP pipe and 5,000 feet of 2-inch PE IP pipe. One new regulator station is also needed for this project. Considering the location and the conditions, much of the project will be installed via open trench with two directional drills for highway crossings to avoid underground conflicts.

Timing

Design for the pipeline will begin in October 2018 and is scheduled to be completed in November 2018. Construction of the project is anticipated to begin November 2018 and estimated to be complete and in service by March 2019.

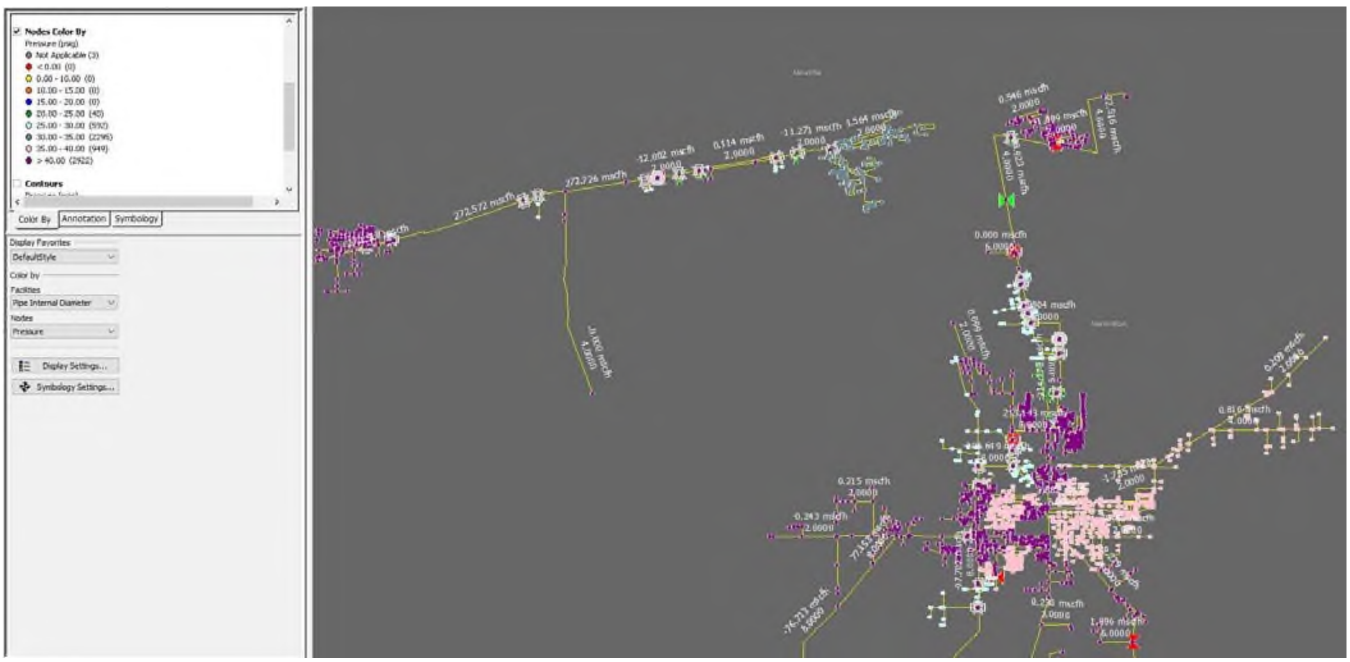
Costs

The estimated costs for the total project including pipeline and regulator station are summarized below:

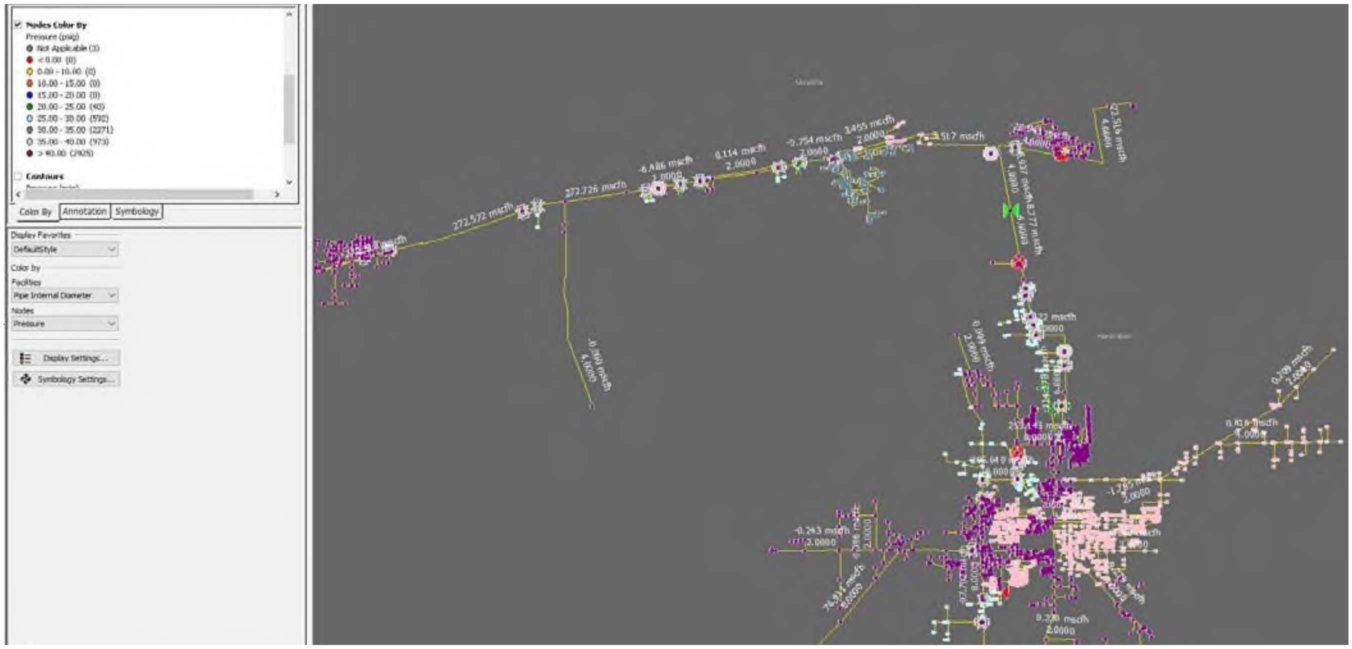
Category	Cost
Materials	$ 50,198
CNGC labor	$ 47,659
Resources	$ 32,416
Contractors	$ 773,281
Overhead	$ 166,434
Total	**$ 1,069,988**

Benefits

1. The second feed into the Umatilla system will allow for isolation to perform necessary maintenance, repair, and replacement of aging facilities in the town of Umatilla.
2. The Synergi diagrams below illustrate the anticipated improvements to the Umatilla system resulting from this project:



Synergi Model: Umatilla/Hermiston – Current Model



Synergi Model: Umatilla/Hermiston – Improved Model Upon Project Completion

Alternatives

No alternatives can be identified with similar scope.

Responsible People

District Contact: Denny Whitsett
Project Engineer: Linda Offerdahl
Project Foreman: TBD
Cascade Inspector: TBD

Project Summary – Redmond 6 in HP Line and New Reg Station – WO# 267431

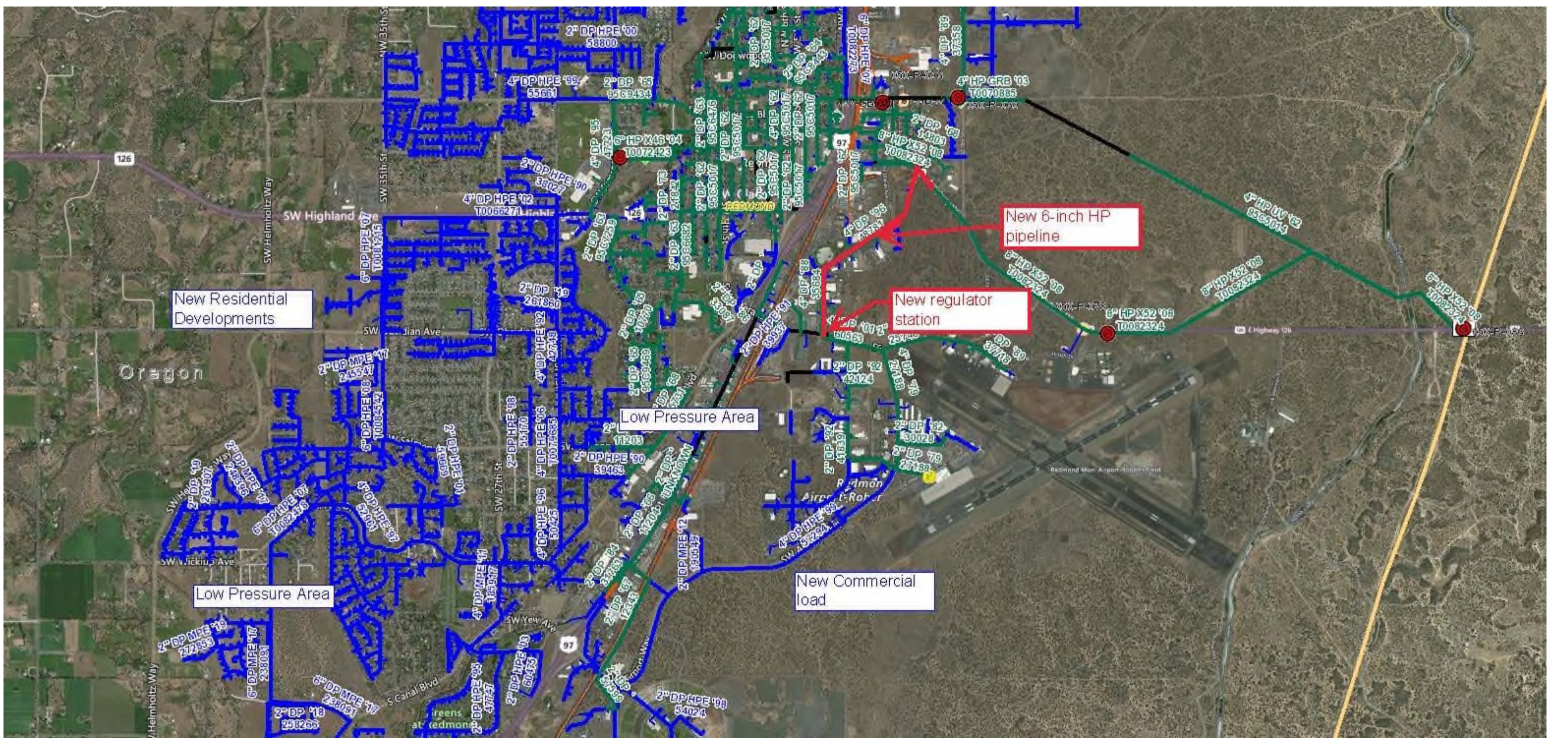
Submitted by Linda Offerdahl

Background

The pressure in the Redmond southern distribution system during peak usage is below design criteria. The existing system does not allow for residential and commercial growth and increased existing commercial loads requested in the southern area of Redmond.[1]

While the City of Redmond does employ several large volume industrial customers, the gas loads of industrial customers on an interruptible rate are not used in distribution planning modeling of the gas system. Cascade only includes core customer loads in determining if reinforcements of the system are necessary on a peak design day. Even with the interruptible customer loads removed, the southern Redmond system, being farthest from the existing high-pressure mains and regulation, consistently experiences low pressures during cold weather events.

The project site starts at E Highway 126 and SE Lake Road and heads southwest to end at Veterans Way. The location is shown on the map below:



Proposal

This project consists of installing approximately 1 mile of 6-inch steel HP pipe and a new regulator station. This pipeline will operate at 300 psig. Considering the location and the conditions, much of the project will be installed via open trench with 3 bores across roadways and to maintain separation from conflicting utilities.

[1] Redmond continues to be one of the strongest housing markets in Central Oregon. Home sales volume in Redmond increased by over 12% in the second quarter of 2019 year over year. The City's Planning Commission recently completed a Housing Grant Project for the Redmond Housing Needs Analysis and Buildable Lands Inventory, according to the analysis, approximately 7,000 housing units are needed over the next 20 years.

Project Summary – Redmond 6 in HP Line and New Reg Station – WO# 267431

Submitted by Linda Offerdahl

Timing

Design for the pipeline will be complete by March 2020. Construction is planned to begin April 2020 and estimated to be complete and in-service by May 2020.

Costs

The estimated costs for the total project, including pipeline and regulator station, are summarized below:

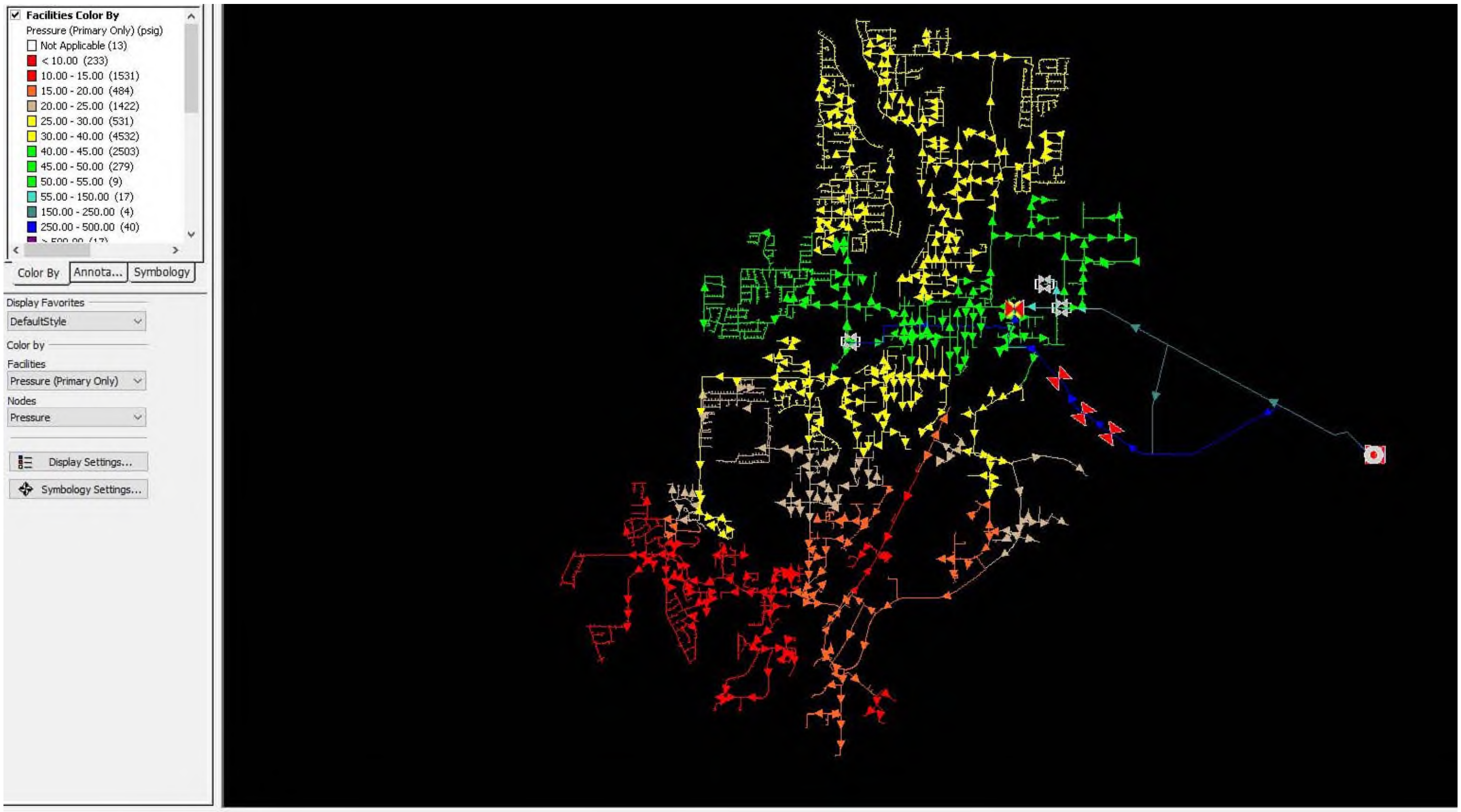
Materials	$	193,755.58
CNGC Labor	$	45,076.02
Contractor Costs	$	919,455.43
Resources	$	42,009.00
Total Direct Costs	**$**	**1,200,296.03**
Corporate Overhead	**$**	**176,203.46**
Total Estimated Project Costs	**$**	**1,376,499.49**

Benefits

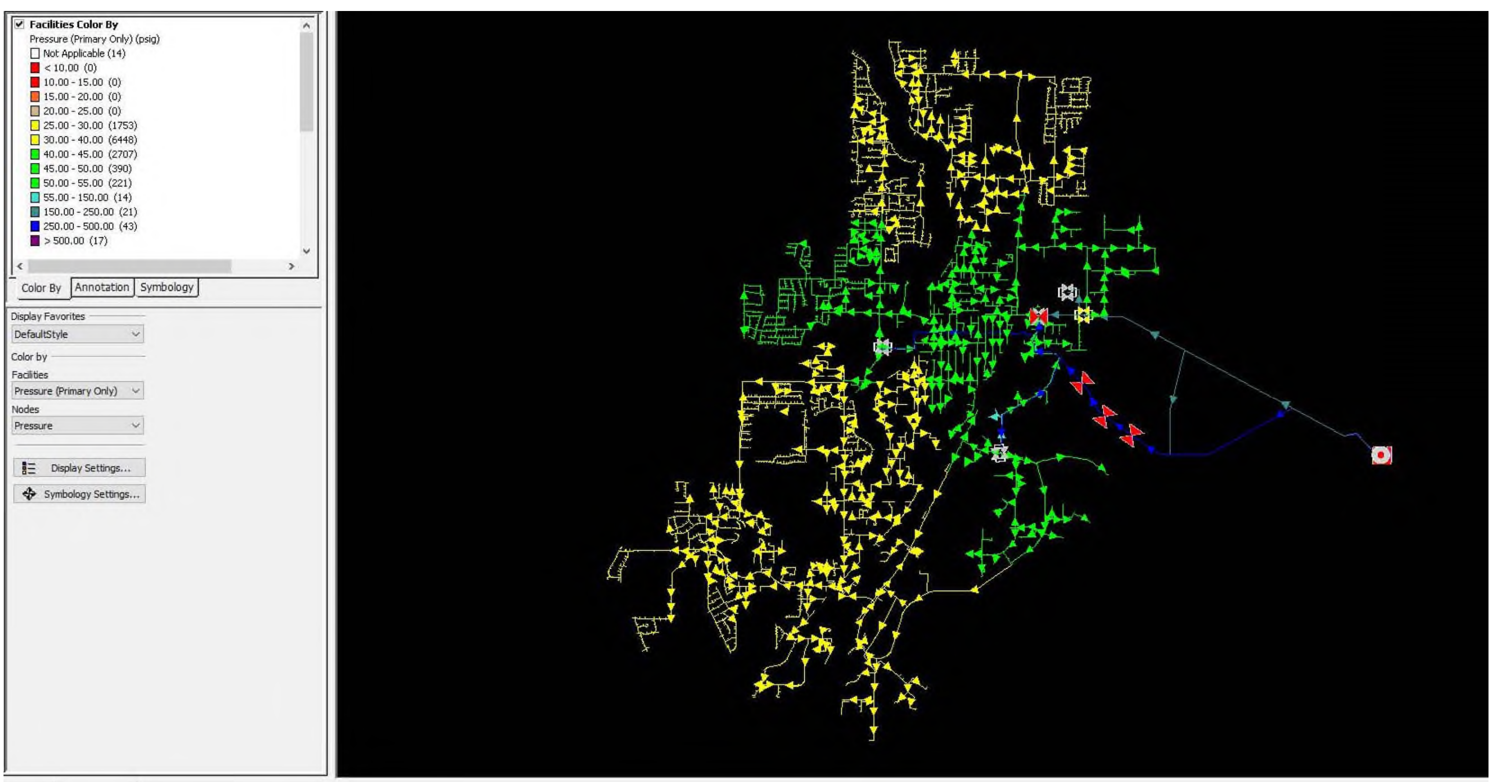
1. New HP pipeline and regulator station will bring the southern Redmond distribution system above design criteria during peak usage and cold weather events.
2. This project allows for new commercial and residential growth occurring in the area.
3. The Synergi diagrams below illustrate the anticipated improvements to the Redmond system resulting from this project:

Project Summary – Redmond 6 in HP Line and New Reg Station – WO# 267431

Submitted by Linda Offerdahl



Synergi Model: Redmond – Current Model



Synergi Model: Redmond – Improved Model Upon Project Completion

Project Summary – Redmond 6 in HP Line and New Reg Station – WO# 267431

Submitted by Linda Offerdahl

Alternatives

1. No reinforcement: This alternative means that the southern Redmond distribution system will continue to experience low pressures during peak usage and cold weather events. In addition, by not installing a reinforcement Cascade is unable to provide gas service to new residential and commercial customers and existing customers wanting to increase their commercial gas load in the southern Redmond distribution system.
2. Postponing reinforcement: Residential and commercial growth is occurring in the City of Redmond currently and growth is anticipated to continue to increase. By not bringing higher pressure and regulation closer to the load, this will affect Cascade's ability to provide service to new residential and commercial customers and existing customers wanting to increase their commercial gas load in the southern Redmond distribution system. Not installing gas main while developments and construction are in progress, make it difficult and expensive to install gas main and services at a later date when the system capacity is increased and new neighborhoods are built out with finished infrastructure (roads, sidewalks, storm, sewer, water, phone, cable, and power).
3. Shorter reinforcement: This alternative looked at making the new pipe installation shorter (2,000 feet) putting the high pressure and regulator station farther from the existing and new load. This option provided some improvements in the southern Redmond distribution system, however there were still areas experiencing low pressure and not allowing for new requested added load.

Responsible People

District Operations Manager: Josh Aigner
District Manager: Marcus McCloskey
Project Engineer: Linda Offerdahl
Project Foreman: TBD
Cascade Inspector: TBD

Project Summary – Bend 6 in PE Ponderosa St Reinforcement – WO# TBD

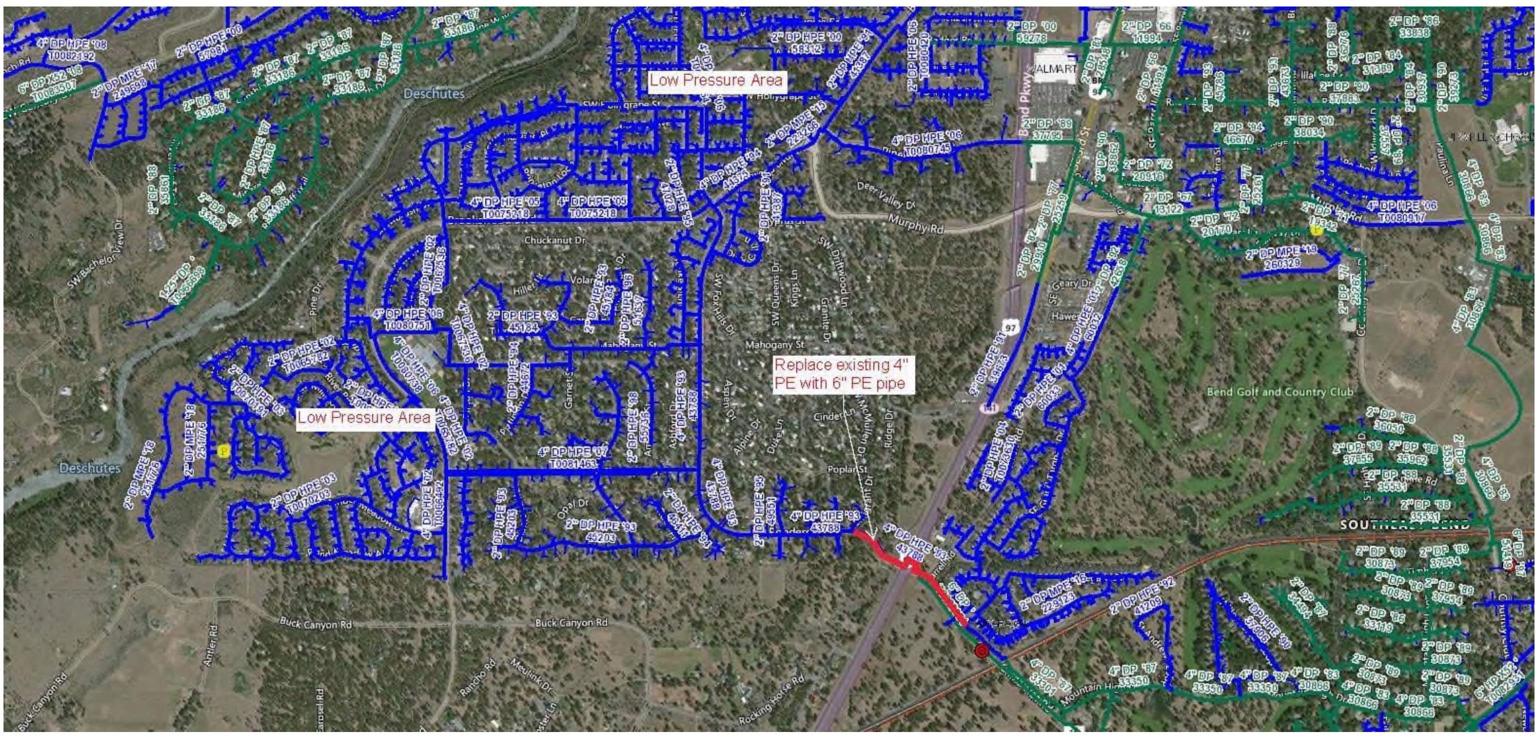
Submitted by Linda Offerdahl

Background

The pressure in the Bend southcentral distribution system during peak usage is below design criteria and the system is isolated due to the river on the west and the highway to the east. This scenario results in the district needing to perform bypass during cold weather events and restricts the ability to install reinforcement loops from areas of the system above design criteria.

Several reinforcement projects for this area have been reviewed to determine which option offers the greatest system improvement, and is constructible, for the least cost. The reinforcement that meets this criterion is increasing the size of approximately 1,200 ft of existing 4-inch PE in Ponderosa Street coming out of R-84, the regulator station that feeds this area.

The project site starts at China Hat Road and Stonegate Drive and heads northwest to end at Ponderosa Street and Emigrant Drive. The location is shown on the map below:



Proposal

This project consists of replacing approximately 1,200 feet of 4-inch PE pipe with 6-inch PE pipe. This pipeline will operate at 60 psig. Considering the location and the conditions, much of the project will be installed via open trench with one insertion in the existing 8-inch casing crossing Highway 97.

Timing

Design for the pipeline will be complete in April 2020. Construction is anticipated in early July 2020 to utilize the lower summer flows and two-way feeds by installing the new pipe while removing the old pipe, a City of Bend requirement.

Project Summary – Bend 6 in PE Ponderosa St Reinforcement – WO# TBD

Submitted by Linda Offerdahl

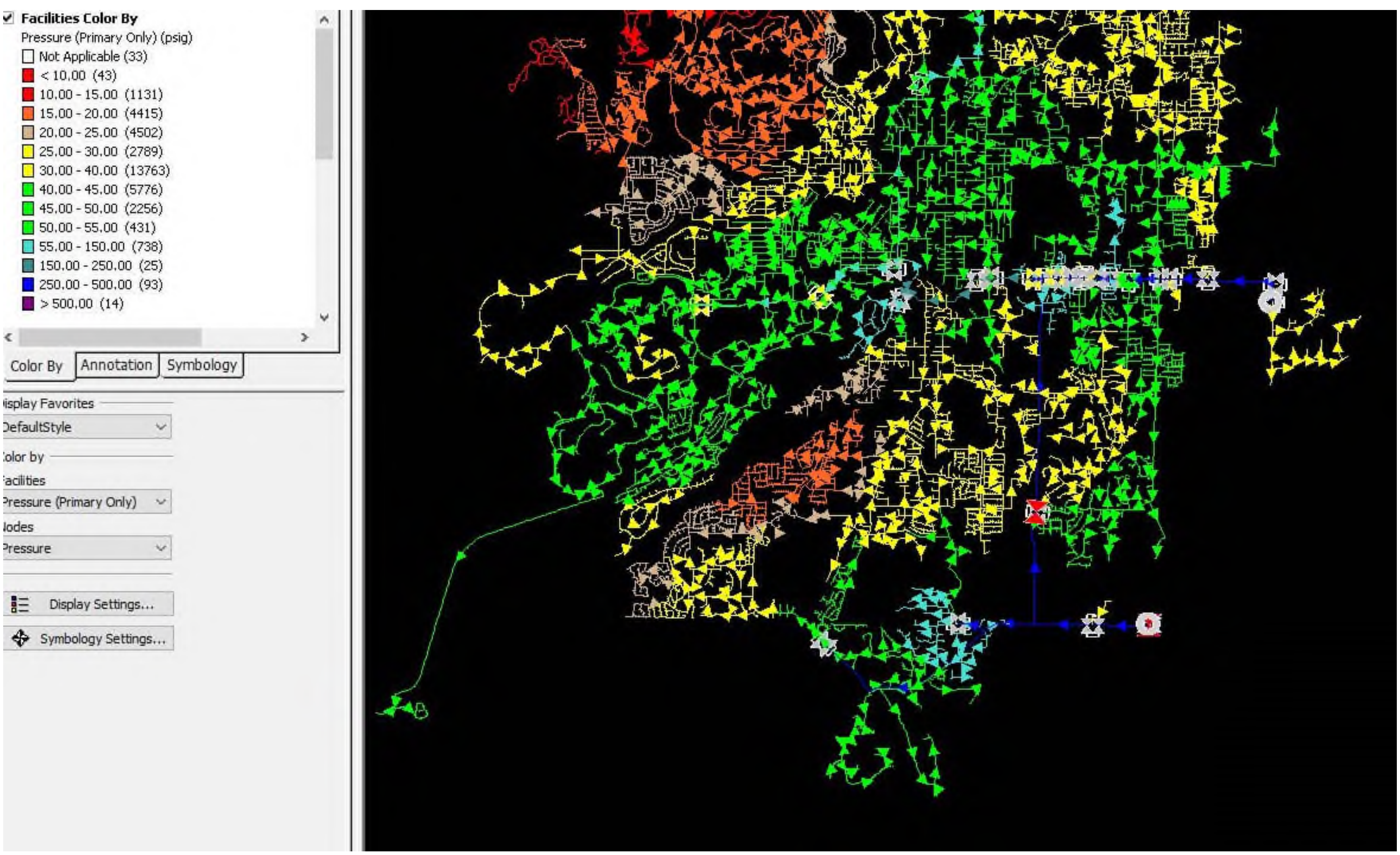
Costs

The estimated costs for the total project are summarized below:

Materials	$	10,941.04
CNGC Labor	$	4,719.94
Contractor Costs	$	186,688.20
Other Direct Costs	$	2,275.20
Total Direct Costs	$	204,624.37
Corporate Overhead	$	27,405.83
Total Estimated Costs	**$**	**232,030.20**

Benefits

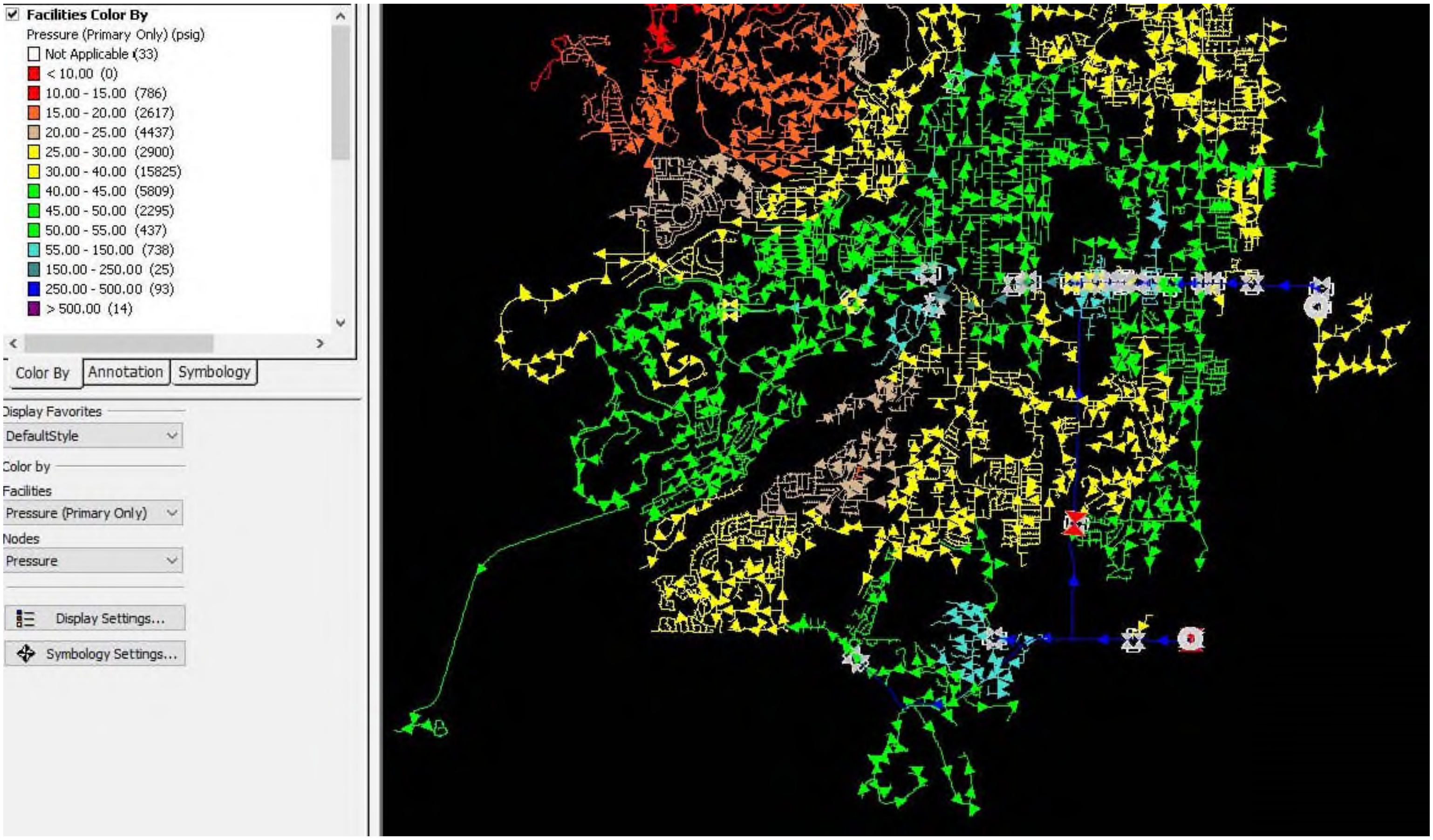
1. New 6-inch pipeline will bring the southcentral Bend distribution system above design criteria and eliminate the need to bypass during peak usage and cold weather events.
2. The Synergi diagrams below illustrate the anticipated improvements to the Bend system resulting from this project:



Synergi Model: Bend – Current Model

Project Summary – Bend 6 in PE Ponderosa St Reinforcement – WO# TBD

Submitted by Linda Offerdahl



Synergi Model: Bend – Improved Model Upon Project Completion

Alternatives

1. No reinforcement: This alternative means that district personnel will need to bypass during cold weather events to keep system pressures in the southcentral Bend system deliverable to the customer. There are many factors that affect the decision to bypass regulation, some of these factors are dependent on current temperatures, inlet pressure from the transmission company, time of day, and flow rates. Due to these fluctuating variables, is difficult to make a concrete rule on when bypass needs to occur and instead requires close on-site system observation often occurring in extreme weather conditions. There are risks involved with bypass operations with personnel required to manually bypass regulation and closely monitor system pressures to prevent over pressuring the downstream pipeline systems and customer services and meters. Other risks include not performing bypass operations soon enough and potentially losing gas service to thousands of customers.
2. Alternate Route 1: An evaluation was completed to install 600 feet of 4-inch PE pipe under Highway 97 to connect the distribution system on SE Hayes Avenue. Upon further review it was determined that due to other utility conflicts and the widened highway in the area, this route is not practical for construction. In addition, where the connections occur and feed into the system, this option would not provide the greatest improvement in system capacity.
3. Alternate Route 2: A review was conducted to replace approximately 1,500 feet of 2-inch steel pipe with 4-inch steel pipe in SE Badger Road. However, due to the permiting requirements from the City of Bend to remove all abandoned pipe when installing new pipe in its place, this project was determined to be too costly for the system benefit.

Project Summary – Bend 6 in PE Ponderosa St Reinforcement – WO# TBD

Submitted by Linda Offerdahl

Responsible People

District Operations Manager: Josh Aigner
District Manager: Marcus McCloskey
Project Engineer: Linda Offerdahl
Project Foreman: TBD
Cascade Inspector: TBD

AWEC DATA REQUEST NO. 3

Date prepared: June 30, 2020

Preparer: Linda Offerdahl/Ryan Privatsky

Contact: Christopher Mickelson

Telephone: (509)-734-4549

AWEC DR 3 TO CASCADE:

Please refer to CNGC/200, Darras/8 and 9.

a. Please provide all budgeting documentation retained by Cascade for each capital project in 2019 and 2020.
b. Please provide all project management documentation retained by Cascade for each capital project in 2019 and 2020.

Response:

a. See attached AWEC-3 UM 2026 CNGC Exh. 100, 2019 Safety Cost Recovery Mechanism Testimony of Michael P. Parvinen and Ryan Privratsky. Also, see attached project executive summaries AWEC-2A, AWEC-2B, and AWEC-2C.pdf.

b. See attached AWEC-3 UM 2026 CNGC Exh. 100, 2019 Safety Cost Recovery Mechanism Testimony of Michael P. Parvinen and Ryan Privratsky.Also, see attached project executive summaries AWEC-2A, AWEC-2B, and AWEC-2C.pdf.

Funding Project	FP Description	FP Type	Ledger Type	Total (Actuals)
FP-101163	Gas Work Equipment-CNGC	Blanket	UO	(8,619.07)
FP-101170	MAIN-GROWTH-OREGON	Blanket	UO	2,503,564.29
FP-101171	MAIN-REINFORCE-OREGON	Blanket	UO	23.44
FP-101172	MAIN-RELO-REPL-OREGON	Blanket	UO	653,437.62
FP-101173	R STA-GROWTH-OREGON	Blanket	UO	73,464.61
FP-101174	R STA-REINFORCE-OREGON	Blanket	UO	132,681.61
FP-101175	R STA-RELO-REPL-OREGON	Blanket	UO	(37,654.44)
FP-101176	SERV-GROWTH-OREGON	Blanket	UO	85,569.59
FP-101177	SERV-RELO-REPL-OREGON	Blanket	UO	632,566.81
FP-101178	STD M&R-GROWTH-OREGON	Blanket	UO	77,525.92
FP-101179	STD M&R-RELO-REPL-OREGON	Blanket	UO	456.61
FP-101180	IND M&R-GROWTH-OREGON	Blanket	UO	151,350.12
FP-101181	IND M&R-REMOVE&REPLACE-OREGON	Blanket	UO	79,053.86
FP-101184	GP TRAN. VEHICLE - OREGON	Blanket	UO	559,984.22
FP-101186	GP POWER EQUIP - OREGON	Blanket	UO	178,389.03
FP-101196	Dist Reg Station Replace Washington	Blanket	UO	-
FP-101200	IND M&R-GROWTH-WASHINGTON	Blanket	UO	4,051.38
FP-101204	GP TRAN. VEHICLE - WASHINGTO	Blanket	UO	18,310.58
FP-101210	Gas Meters-Total Company CNGC	Blanket	UO	608,529.41
FP-101213	GP BUILDINGS - INTERSTATE	Blanket	UO	8,584.00
FP-101215	Gas Vehicles-CNGC	Blanket	UO	55,417.29
FP-101216	GP TOOLS - INTERSTATE	Blanket	UO	38,723.03
FP-101218	GP TOOLS - BEND	Blanket	UO	17,554.53
FP-101237	GP TOOLS - PENDLETON	Blanket	UO	34,597.97
FP-101255	GP TOOLS - ONTARIO	Blanket	UO	11,673.70
FP-101259	Gas Regulators-Total Company CNGC	Blanket	UO	192,128.76
FP-101480	UG-Work Asset Management	Other	UO	293,300.85
FP-200064	UG-Customer Self Service Web/IVR	Other	UO	27,229.23
FP-200268	CNGC Engineering & Supervision	Blanket	UO	24,099.14
FP-200269	CNGC General & Administrative	Blanket	UO	(375.77)
FP-200282	R STA - SUN RIVER GATE UPGRADE	Other	UO	(637.17)
FP-200661	Data Center & Network Equipment	Blanket	UO	24,813.12
FP-200662	Personal Computers & Peripherals	Blanket	UO	41,893.57
FP-200663	UG-GIS Enhancements CNGC	Other	UO	9,285.03
FP-200688	BEND PIPE REPLACEMENT	Other	UO	1,867.28
FP-200689	RPL; 6" HP, BEND HP PH1	Other	UO	544,556.51
FP-302370	Gas Cathodic Protection - OR	Blanket	UO	133,218.97
FP-302640	6" PILOT ROCK HP REPLACEMENT	Other	UO	-
FP-302641	4" PILOT ROCK IP REINFORCEMENT	Other	UO	-
FP-306989	UMATILLA 2" REINFORCEMENT	Other	UO	512,780.98
FP-306997	RPL; 4" HP, MADRAS PH1	Other	UO	15,679.58
FP-308022	ERT Replacement - 2018	Blanket	UO	0.13
FP-308023	ERT Replacment 2019	Blanket	UO	1,802,717.98
FP-311939	UG-PCAD Upgrade to v6.5	Other	UO	(656.12)
FP-311999	0-1 Mission	Other	UO	63,213.46
FP-312013	RP; REG STA R-9 Weston	Other	UO	(490.97)

FP-313181	CNGC Payroll Accrual	Blanket	UO	16,105.64
FP-313621	FAMILY METER REPLACEMENT	Other	UO	(0.03)
FP-315865	UG-ThoughtSpot Implementation Prj	Other	UO	18,899.97
FP-316019	UG-GIS ESRI System Upgrade	Other	UO	13,783.34
FP-316047	UG-GIS Landbase Repl and Enhanc	Other	UO	1,837.66
FP-316182	UG-CC&B Upgrade to 2.6+	Other	UO	84,303.88
FP-316243	RF; 4" PE; BEND; 1,200' ARCHIE BRIG	Other	UO	97,000.34
FP-316245	RP; O-TBD(O-4) BAKER CITY	Other	UO	76,731.94
FP-316269	UG - JDE Weblogic - CNGC	Other	UO	(240.96)
FP-316289	UG - PowerPlan Lease - CNGC	Other	UO	6,892.76
FP-316361	UG-GAS SCADA System Enhancements	Other	UO	9,321.32
FP-316401	RP; 2,4" BRIDGE XINGS, BAKER CITY	Other	UO	391,062.86
FP-316445	Toughbook Replacements-CNG	Blanket	UO	19,175.58
FP-316447	UG-PragmaFIELD Implementation	Other	UO	20,743.52
FP-316451	UG-PCAD Annual Enhancements-CNG	Other	UO	1,633.91
FP-316478	27th St Bore Canal Bend	Other	UO	(0.02)
FP-316479	Bend River Mall Main RPL Bend	Other	UO	24,562.51
FP-316573	RPL; 4" HP, MADRAS PH2	Other	UO	1,819,895.11
FP-316575	MAOP; 12" HP; BEND; 5,500' PHASE 2	Other	UO	732,296.71
FP-316697	RP; 4" ST; BEND; 2,500' PH 7 SEC 1	Other	UO	553.95
FP-316698	RP; 1/2" SL; BEND; PH 7 SEC 1 SERVI	Other	UO	3,296.34
FP-316832	Office Structure & Eq-Kennewick GO	Blanket	UO	954.22
FP-316845	O-9 Replacement South Hermiston Gat	Other	UO	66,691.38
FP-316853	Verizon 3G Modem Replacement	Other	UO	82,675.98
FP-317047	UG-GAS SCADA Implement DR System	Other	UO	8,233.50
FP-317050	UG-GAS SCADA Upgrade Autosol EFM	Other	UO	4,370.33
FP-317078	Itron Mobile Radio (IMR)-CNG	Other	UO	19,742.89
FP-317103	UG-PowerPlan Upgrade to 2018.X	Other	UO	41,858.16
FP-317120	Purch Training Props for Sunnyside	Other	UO	8,884.66
FP-317235	2" ST; BEND; 750' PH 7 SEC 2	Other	UO	(11,272.74)
FP-317299	Iton Mobile Radio-Early Install	Other	UO	(146.45)
FP-317301	GR; 4" HP; HERM; 2,600' LAMB WESTON	Other	UO	47,548.80
FP-317307	Repl MN/Bore @Purcell Blvd Bend	Other	UO	88,135.54
FP-317311	RP; 1/2" SL; BEND; PH 7 SEC 2 SERVI	Other	UO	5,555.90
FP-317321	Bathroom Remodel - Sunnyside Traini	Other	UO	0.17
FP-317334	Purchase Quanta-Fit CNGC	Other	UO	-
FP-317349	RP; 8" ST; PENDLETON; 1960' PH 2	Other	UO	1,022,489.33
FP-317393	RP; 1/2" SL; PEND; PH 2 SERVICES	Other	UO	(484,207.35)
FP-317417	One 8" Mueller Shell Cutter	Other	UO	1,720.89
FP-317435	PUR INDOOR UTILITY GROUP SIGNS	Other	UO	953.13
FP-317451	FRL; 4" HP; SUNR; 500'	Other	UO	40,682.49
FP-317454	Purch Digital Gauges	Other	UO	765.23
FP-317465	Purch One 8" Mueller Stopper	Other	UO	985.33
FP-317485	MUELLER EQUIPMENT FOR FAB SHOP	Other	UO	15,228.61
FP-317505	RP; 2" ST; BEND; 4,610' PH 8 SEC 1	Other	UO	1,297,568.18
FP-317506	REPL 2" STL MN SE 2ND ST BEND	Other	UO	-
FP-317523	RP; 3/4" SL; BEND; PH 8 SEC 1 SERV	Other	UO	272,380.01

FP-317551	Construct Sign Bend Office Building	Other	UO	604.22
FP-317554	UG-Install Meter Mgmt System CNG	Other	UO	290.09
FP-317581	GR; 4"HP ; M-F; 4000' CWA	Other	UO	67,720.15
FP-317617	UG-Migrate Aligne To Vendor CNG	Other	UO	2,104.67
FP-317662	SERV-GROWTH-EASTERN OREGON DISTRICT	Blanket	UO	119,016.47
FP-317666	SERV-GROWTH-PENDLETON DISTRICT	Blanket	UO	446,938.45
FP-317756	SERV-GROWTH-BEND DISTRICT	Blanket	UO	3,502,555.44
FP-318375	GR-IRRIGON-R-110	Other	UO	69,552.70
FP-318461	GR-IRRIGON-4" S MAIN	Other	UO	481,600.14
FP-318822	Impl myWorld Leak Survey-CNG	Other	UO	32,620.63
FP-319114	RF Hermiston 2" steel R-26	Other	UO	54,812.81
FP-319225	UG-Install Risk Mgmt Swft-CNG	Other	UO	3,618.70
FP-319230	RP; 2" ST; BEND; 2,528' PH 8 SEC 2	Other	UO	197,205.61
FP-319231	RP; 3/4" SL; BEND; PH 8 SEC 2 A SER	Other	UO	66,046.67
FP-319249	Instl Main Westgate Ph 1-4 Bend	Other	UO	73,130.31
FP-319255	REPL; 13 3/4" SL; BAKER CITY	Other	UO	66,591.72
FP-319284	12" Mueller Shell Cutter and Stoppe	Other	UO	1,374.10

Work Order	Work Order Description	FP Type	Ledger Type	Total
FP-101164	GP COMM EQUIP - INTERSTATE	Blanket	UO	19,654.93
FP-101170	MAIN-GROWTH-OREGON	Blanket	UO	387,566.00
FP-101172	MAIN-RELO-REPL-OREGON	Blanket	UO	473,195.00
FP-101176	SERV-GROWTH-OREGON	Blanket	UO	2,844,250.00
FP-101177	SERV-RELO-REPL-OREGON	Blanket	UO	320,655.00
FP-101178	STD M&R-GROWTH-OREGON	Blanket	UO	111,676.56
FP-101179	STD M&R-RELO-REPL-OREGON	Blanket	UO	331,980.91
FP-101180	IND M&R-GROWTH-OREGON	Blanket	UO	73,402.08
FP-101181	IND M&R-REMOVE&REPLACE-OREGON	Blanket	UO	122,336.92
FP-101184	GP TRAN. VEHICLE - OREGON	Blanket	UO	675,365.60
FP-101186	GP POWER EQUIP - OREGON	Blanket	UO	118,808.56
FP-101187	GP COMM EQUIP - INTERSTATE	Blanket	UO	20,163.80
FP-101210	PRE-CAP MTR-GROWTH-INTERSTAT	Blanket	UO	751,904.28
FP-101213	GP BUILDINGS - INTERSTATE	Blanket	UO	3,804.19
FP-101215	GP TRAN. VEHICLE - INTERSTAT	Blanket	UO	18,604.93
FP-101216	GP TOOLS - INTERSTATE	Blanket	UO	36,178.13
FP-101237	GP TOOLS - PENDLETON	Blanket	UO	51,529.24
FP-101255	GP TOOLS - ONTARIO	Blanket	UO	16,336.08
FP-101259	PRE-CAP REG-GROWTH-INTERSTAT	Blanket	UO	170,793.00
FP-101480	UG WAM PROJECT ¿ CNGC SHARE	Other	UO	319,059.21
FP-200064	IVR-WEB IMPLEMENTATIION - DRCT	Other	UO	29,890.78
FP-200661	DATA CENTER/NETWORKING EQUIP	Blanket	UO	9,510.48
FP-200662	PC SUPPORT EQUIPMENT	Blanket	UO	28,429.97
FP-200663	UG GIS ENHANCEMENTS CNG DIRECT	Other	UO	31,188.65
FP-200688	RPL BEND PHASE 2	Other	UO	2,877,736.39
FP-302370	GB - GROUNDBED OREGON	Blanket	UO	291,706.28
FP-302621	LV Customer Website Upgrade	Other	UO	6,434.85
FP-306967	District Office Access Control Sys	Other	UO	27,103.51
FP-308023	ERT Replacment 2019	Blanket	UO	3,121,453.81
FP-312013	R-9 Weston	Other	UO	25.48
FP-315865	UG - ThoughtSpot Implementation Prj	Other	UO	25,528.44
FP-316019	GIS ESRI System Upgrade - UG	Other	UO	41,162.89
FP-316047	GIS Landbase Repl and Enhanc - UG	Other	UO	45,151.30
FP-316182	UG CC&B Upgrade to 2.6+	Other	UO	59,039.37
FP-316243	RF; 4" PE; BEND; 1,200' ARCHIE BRIG	Other	UO	197,024.53
FP-316401	RP; 2,4" BRIDGE XINGS, BAKER CITY	Other	UO	284,270.17
FP-316407	RF; 4" PE; BEND; 600' HAYES AVE	Other	UO	184,432.46
FP-316445	Toughbook Replacements for Field Op	Blanket	UO	18,691.24
FP-316447	UG-PragmaFIELD Implementation	Other	UO	4,860.10
FP-316451	UG-PCAD Annual Enhancements	Other	UO	14,361.19
FP-316573	MAOP RPL; 4" HP, MADRAS PH2	Other	UO	2,356,938.46
FP-316575	MAOP RPL; 6" HP, BEND HP PH2	Other	UO	1,640,273.71
FP-316832	Office Structure & Equip-GO	Blanket	UO	19,020.96
FP-316845	O-9 Replacement South Hermiston Gat	Other	UO	199,009.60
FP-316853	Verizon 3G Modem Replacement	Other	UO	81,848.64
FP-316915	Pur replacment display devices	Other	UO	12,553.83

FP-317012	UG-PCAD Upgrade to v6.8	Other	UO	51,566.69
FP-317047	UG-GAS SCADA Implement DR System	Other	UO	14,320.51
FP-317050	UG-GAS SCADA Upgrade Autosol EFM	Other	UO	5,321.96
FP-317078	Itron Mobile Radio (IMR)	Other	UO	19,020.96
FP-317101	JDEdwards AS400 to Oracle DB - CNGC	Other	UO	16,486.46
FP-317103	PowerPlan Upgrade to 2018.X - CNGC	Other	UO	41,638.36
FP-317120	Purch Training Props for Sunnyside	Other	UO	14,785.62
FP-317297	UG-PragmaFIELD/Dispatcher Licences	Other	UO	1,136.18
FP-317307	Repl MN/Bore @Purcell Blvd Bend	Other	UO	41,241.30

AWEC DATA REQUEST NO. 4

Date prepared: 07/01/2020

Preparer: Scott Wanner

Contact: Christopher Mickelson

Telephone: (509)-734-4549

AWEC DR 4 TO CASCADE:

Please refer to CNGC/200, Darras/8.

a. Please provide Cascade's capital budget at the most granular level available for 2015 to 2020.
b. Please provide actual capital expenditure from 2015 to 2020.
c. If not included in part a and b, please provide the budget and spending under each blanket project from 2015 to 2020.

Response:

Please see included files as follows:

a) "AWEC-4 01-2015 thru 12-2020 UO Budget by FP.xlsx"
b) "AWEC-4 01-2015 thru 05-2020 UO Actuals by FP.xlsx"
c) FP's in each of the above files are labeled as "Blanket" or "Other". For blanket figures see respective budget and actuals file.

AWEC DATA REQUEST NO. 7

Date prepared: June 29, 2020

Preparer: Ryan Privratsky

Contact: Christopher Mickelson

Telephone: (509)-734-4549

<u>AWEC DR 7 TO CASCADE</u>:

Please refer to CNGC/200, Darras/12.

a. Please explain why this project included main replacement as part of the cover project. Please include any supporting modeling or analysis.
b. Please explain why Cascade selected 12 inch pipe as the appropriate size for this project.
c. Please identify the industry standards considered or applied to determine that the main required cover for safety.
d. Please explain why this project is scheduled for six phases rather than fewer phases.

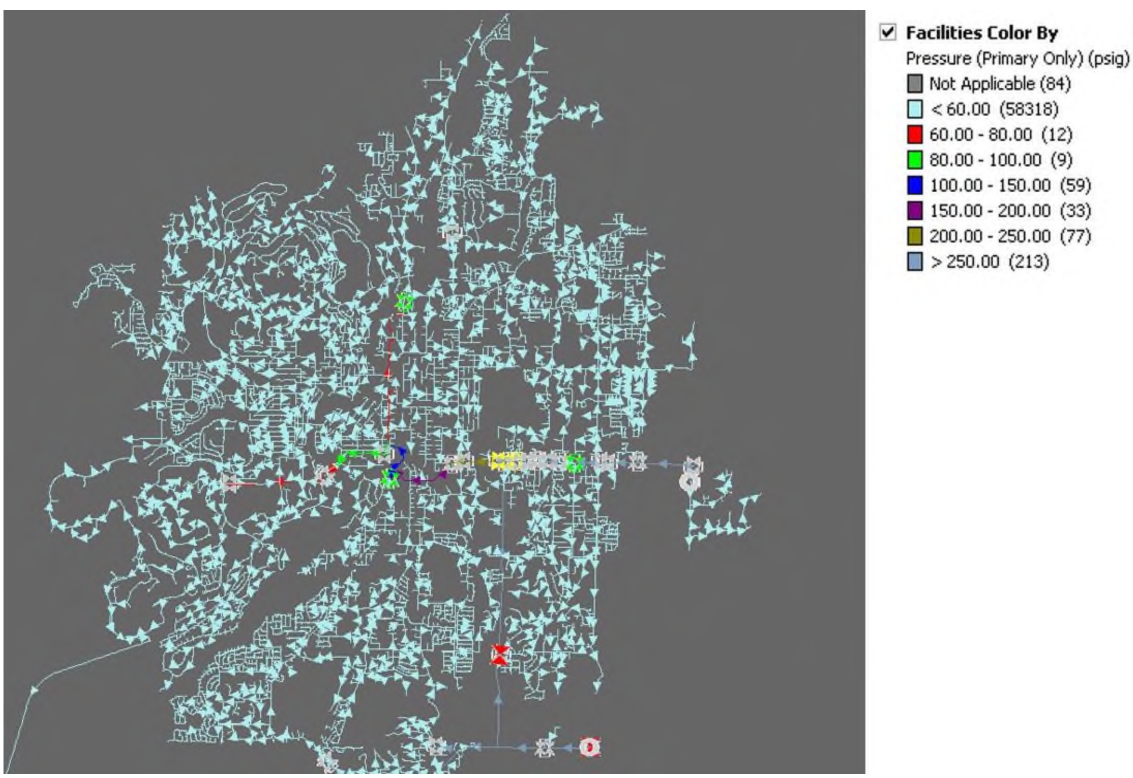
Response:

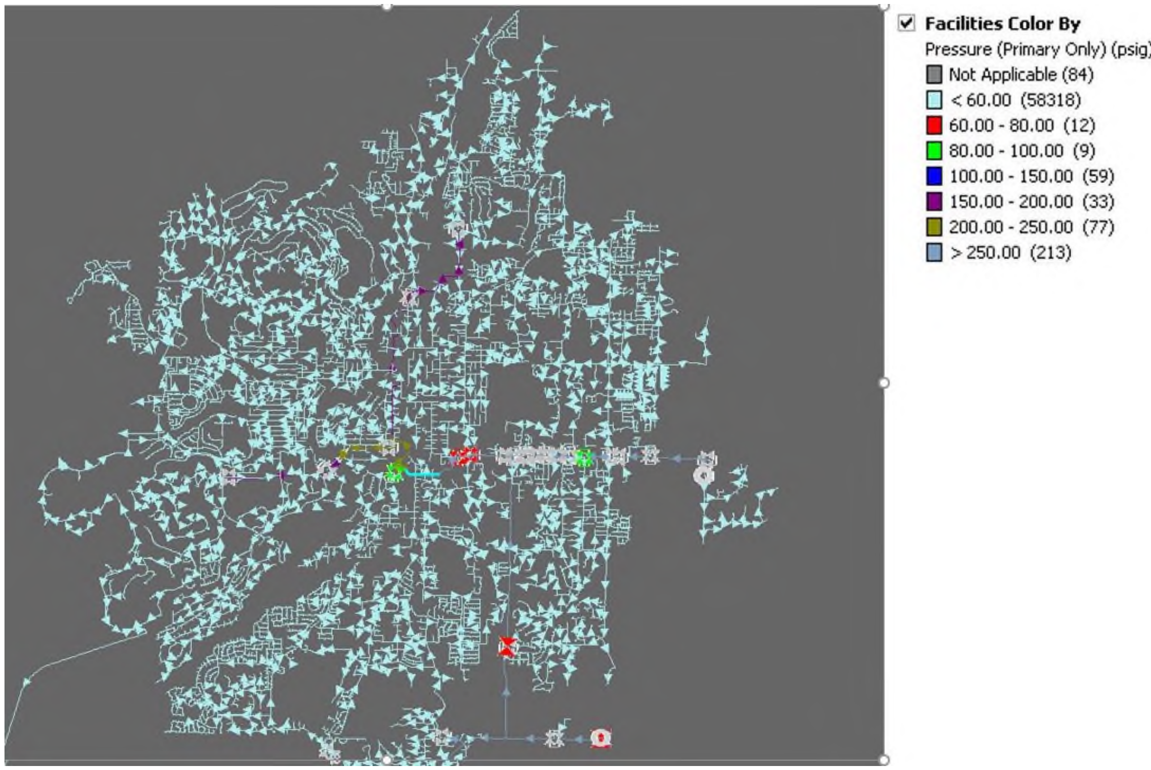
a. Areas with minimal or no cover increases the risk of the pipe being damaged by excavation or from outside forces. This line currently has a high-risk score in the Company's DIMP model and presents a safety issue with not having sufficient cover on a HP line that operates at a maximum allowable operating pressure ("MAOP") of 300 psig.

   Depth of cover varies throughout the pipeline route, areas with a depth of cover less than 24" have been observed at various locations. Depth of cover is measured and recorded on Integrity Management Dig Reports (CNG Form 625) when the pipeline is exposed during construction projects and while observing third party excavators excavate in proximity to the pipeline. Depth of cover is also determined by utilizing pipeline locating equipment which can be used to determine approximate pipeline depths. Field patrols are also utilized to find areas where disturbance has occurred resulting in removal of cover and areas where pipeline is exposed.

b. CNGC is replacing the existing 6" steel with 12" steel, during this replacement, to accommodate the immense growth the City of Bend has been experiencing, which has created constraints to CNGC's distribution system in Bend. Both of the gate stations in Bend feed into the HP system and join up to feed northwest Bend at a regulator station at Bear Creek Rd. and NE 15th St. The northwest area of Bend has been growing as fast as any other area in the city of Bend. The increased capacity installing a 12" will help with CNGC's winter demand in the area and allow for a higher delivery pressure to the northwest part of Bend. CNGC has needed to utilize a cold weather action plan to supplement our system occasionally in the winter. This project, with future phases, will help lessen the possible need for the cold weather action plan and improve system reliability year-round. Exact flow volumes and customers counts are ever changing, but CNGC continues to see steady growth overall.

CNGC has growth data, along with modeling software to simulate our current situation on this pipeline. The replacement was first modeled with 8" pipe but based on the growth and flow it is made the most sense to upsize the pipe size to 12". The images below are from the IRP. The first image shows peak pressures in the pipeline before the project, and the second one after the 12" is installed.





The 12" pipeline lessens flow and pressure loss currently seen to northwest Bend, allows CNGC to maintain service to core customers, avoid possible curtailment, and allows for future growth.

c. Depth of cover requirements are outlined in 49 CFR Part 192.327. Based on 192.327 the 6" Bend HP Line needs a minimum cover of 24 inches. Although 24 inches is allowed per 192.327, CNG company procedures requires a minimum depth of cover of 36 inches for all high pressure and transmission gas pipelines. A depth of cover of at least 36 inches increases pipeline protection and prevention of damage from external forces and third-party excavation.

d. CNGC decided to break this project up into multiple phases to spread the overall project cost over a multiple year timeframe rather than completing fewer larger and more expensive phases. Also, to balance available resources and permitting requirements to complete each phase.

AWEC DATA REQUEST NO. 8

Date prepared: June 25, 2020

Preparer: Linda Offerdahl

Contact: Christopher Mickelson

Telephone: (509)-734-4549

<u>AWEC DR 8 TO CASCADE</u>:

Please refer to CNGC/200, Darras/14 lines 18 to 20.

a. When was the future HP main transferred to plant in service?
b. Is the future HP main included in the proposed ratebase for this case?
c. If yes, please explain why Cascade considers the future HP main used and useful.
d. If yes, please provide the gross plant, accumulated depreciation, and depreciation rate for the amounts in ratebase.

Response:

The Shevlin Park Project has been postponed to 2021 due to COVID-19 impacts. The Company will remove this project from the UG390 request in a rebuttal filing.

Due Date: July 2, 2020

AWEC DATA REQUEST NO. 9

Date prepared:

Preparer:

Contact: Christopher Mickelson

Telephone: (509)-734-4549

AWEC DR 9 TO CASCADE:

Please refer to CNGC/200, Darras/17 lines 4 to 5.

a. Please identify the 10 most recent outages due to low pressure. Please provide all internal documentation of the outages.
b. Please refer to OPUC Docket UG 344, NW Natural/800, Karney/Page 27 lines 14 to 16. Please explain why Cascade believes pressures below 20 psig, but above 10 psig will result in outages.
c. Please provide the criteria for system reinforcement used by each MDU Resources' gas distribution subsidiaries. If the criteria for these subsidiaries differs from Cascade, please explain why.
d. Please identify all new residential development line extensions or connections made from 2015 to present in the region shown in Figure 5.
e. Please identify any planed development that Cascade is aware of in Figure 5 that was not included in response to part d above.
f. Did Cascade make this investment in anticipation of specific new load?

Response:

a. The outage in the Bend area due to low pressure occurred in February 2018 and impacted fewer than 25 residential customers.
b. Cascade (and MDU) utilize a design criterion of 20 psig. If it is shown through system modelling that the pressure in the distribution system is operating below 20 psig then a distribution enhancement analysis is triggered and remediation is initiated depending upon how severe the low pressures may be, where they are occurring, and if the low pressures are occurring at temperatures warmer than the peak or design day temperature. Due to the time it takes to potentially design and construct a distribution enhancement project, the analysis occurs at the 20 psig design criteria to plan for budgeting projects within a five year time frame.

c. All of the MDU subsidiaries utilize the 20 psig design criteria for distribution systems that are operating above 20 psig.

Questions d through e above are in reference to the testimony regarding the Shevlin Park Project which has been postponed to 2021 due to COVID-19 impacts. The Company will remove this project from the UG390 request in a rebuttal filing.

AWEC DATA REQUEST NO. 12

Date prepared: June 30, 2020

Preparer: Linda Offerdahl

Contact: Christopher Mickelson

Telephone: (509)-734-4549

AWEC DR 12 TO CASCADE:

Please refer to CNGC/200. Please provide the following information for each Synergi model presented in this testimony:

a. Please identify each symbol
b. Temperature of design day
c. Gas demand of design day
d. Basis for gas demand, including any models if forecasted or weather adjusted.
e. Year of design day
f. Date of analysis.

Response:

a. The lines shown in the Synergi models represent pipe, the colors represent pressure range that the pipe is operating at given the temperature and customer loading conditions, the arrows represent direction of gas flow, the gray open circles (doughnut shaped) represent the gate stations (where Cascade takes the gas from the interstate transmission company), the double bow-tie symbols represent Cascade's regulator stations where the gas is regulated from high pressure to distribution pressure (the pressure delivered to the customer), and the single bow ties represent valves (red if normally closed, green if normally opened).
b. The peak heating degree day (HDD) used for the Bend District (shown in the Synergi models throughout the Darras testimony) is 71, which calculates to a temperature (Peak HDD = 60deg – coldest temp) of -11degF.
c. The gas demand on a peak HDD in the City of Bend Synergi model (shown in the Darras Figures 7 & 8) is 1,533 mcfh. The gas demand on a peak HDD in Redmond Synergi model (shown in Darras Figures 11 & 12) is 493 mcfh.
d. The gas demand is based upon current connected load of the firm customers and a peak HDD of 71.
e. The peak HDD of 71 is based on the coldest day in the past 30 years from December 21, 1990.

f. The date of analysis of the Redmond project was in March 2019 the date of analysis of the Pondersossa Reinforcement project was in May 2019.

AWEC DATA REQUEST NO. 19

Date prepared: July 22, 2020

Preparer: Ryan Privratsky

Contact: Christopher Mickelson

Telephone: (509)-734-4549

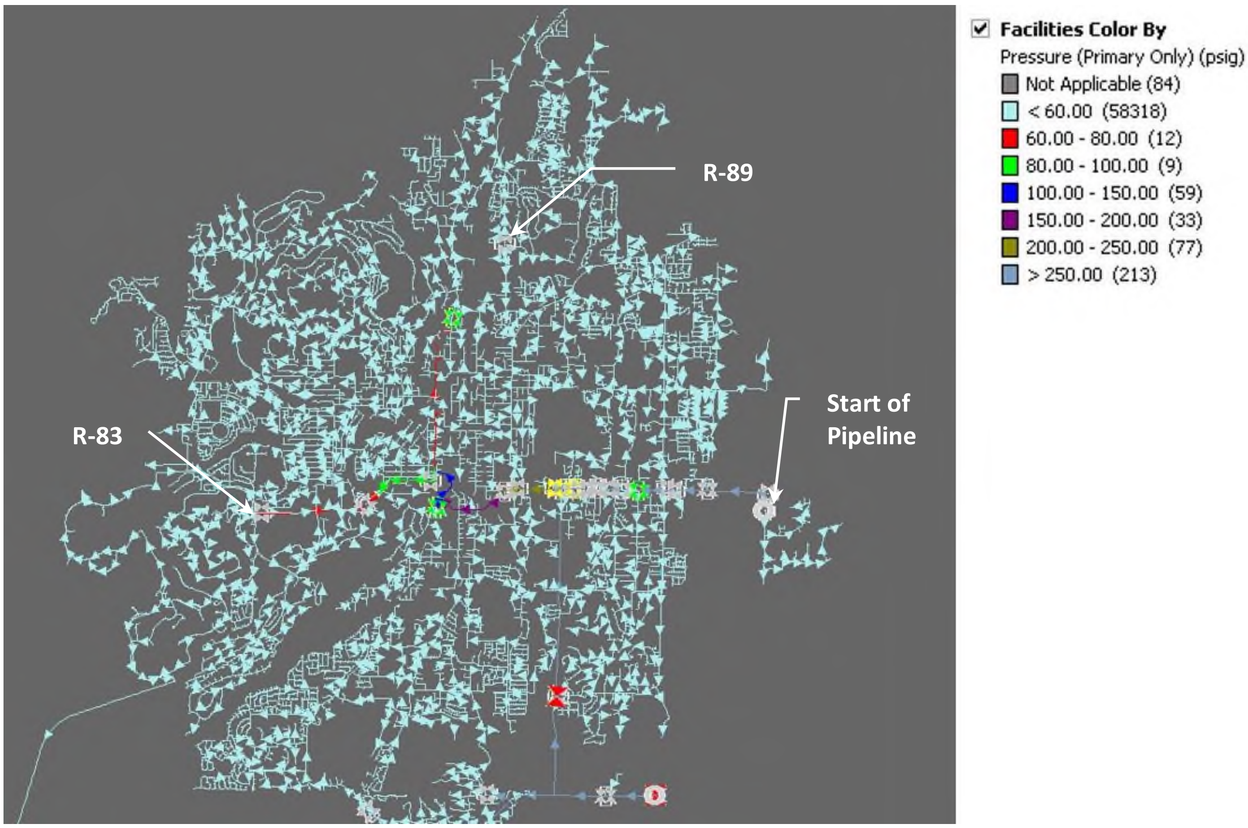
AWEC DR 19 TO CASCADE:

"Please refer to the response to AWEC DR 7.
a. Please provide the study results of the 8 inch pipe.
b. Please provide the distribution pressures below 60 PSI broken out into 5 psi increments. Please provide such data for the 6 inch, 8 inch, and 12 inch pipe.
c. Please provide the cost of the project using a 6 inch and 8 inch pipe."

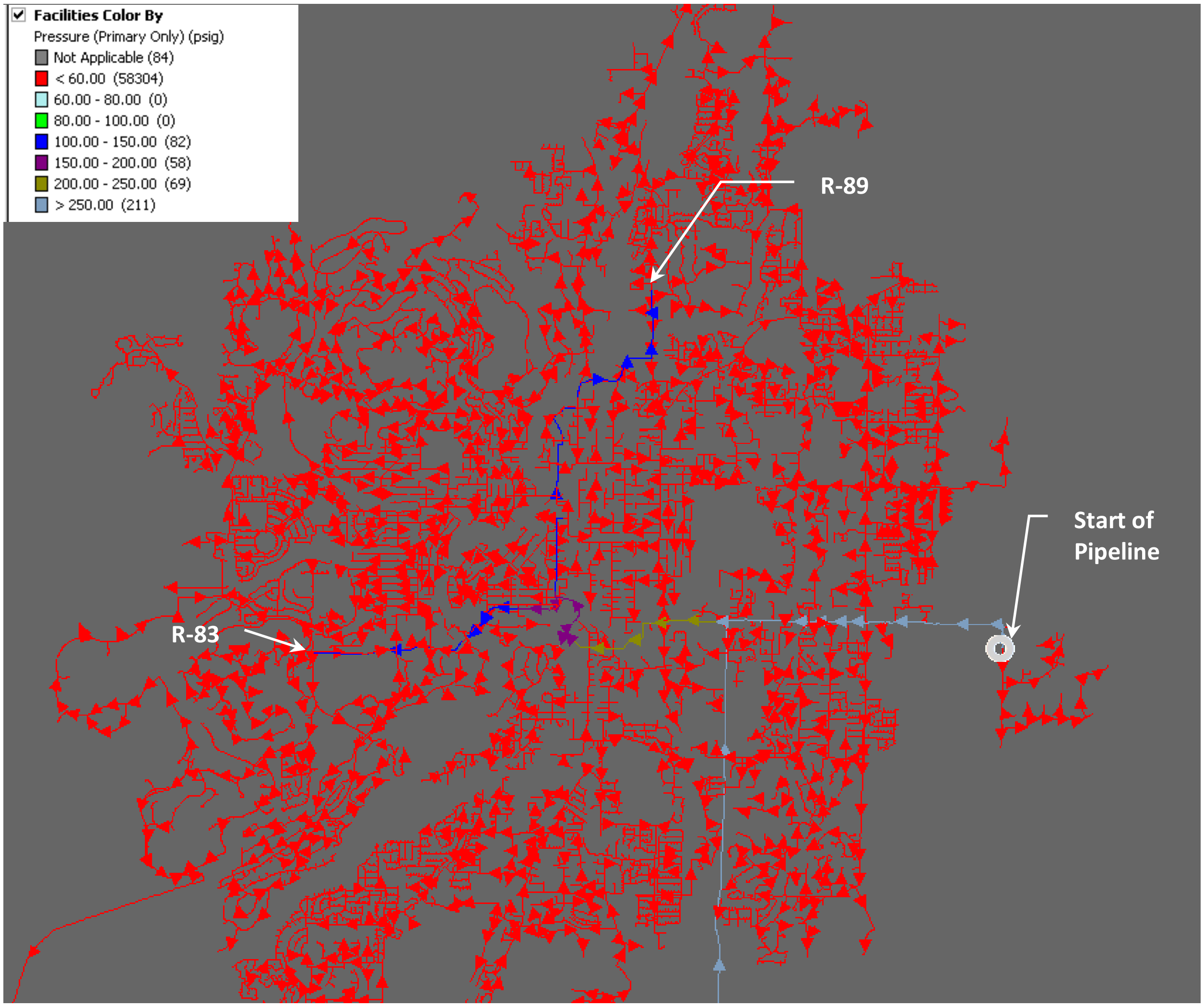
Response:

a. Current modeling, with the existing 6", shows an inlet pressure of approximately 69 psig at R-83 and 49 psig at R-89 during peak demand. Actual pressure data from October 2017, the inlet pressure to R-83 and R-89 got down to 75 psig and 67 psig, respectively. Installation of an 8" pipeline increases the inlet pressure to between 100 psig – 150 psig during peak demand at R-83 and R-89. Installation of a 12" pipeline increase the inlet pressure to between 150 psig – 200 psig during peak demand at R-83 and R-89. The current maximum allowable operating pressure (MAOP) of the system is 300 psig. The 12" pipeline lessens flow and pressure loss currently seen to northwest Bend (R-89), allows CNGC to maintain service to core customers, avoid possible curtailment, and allows for future growth.

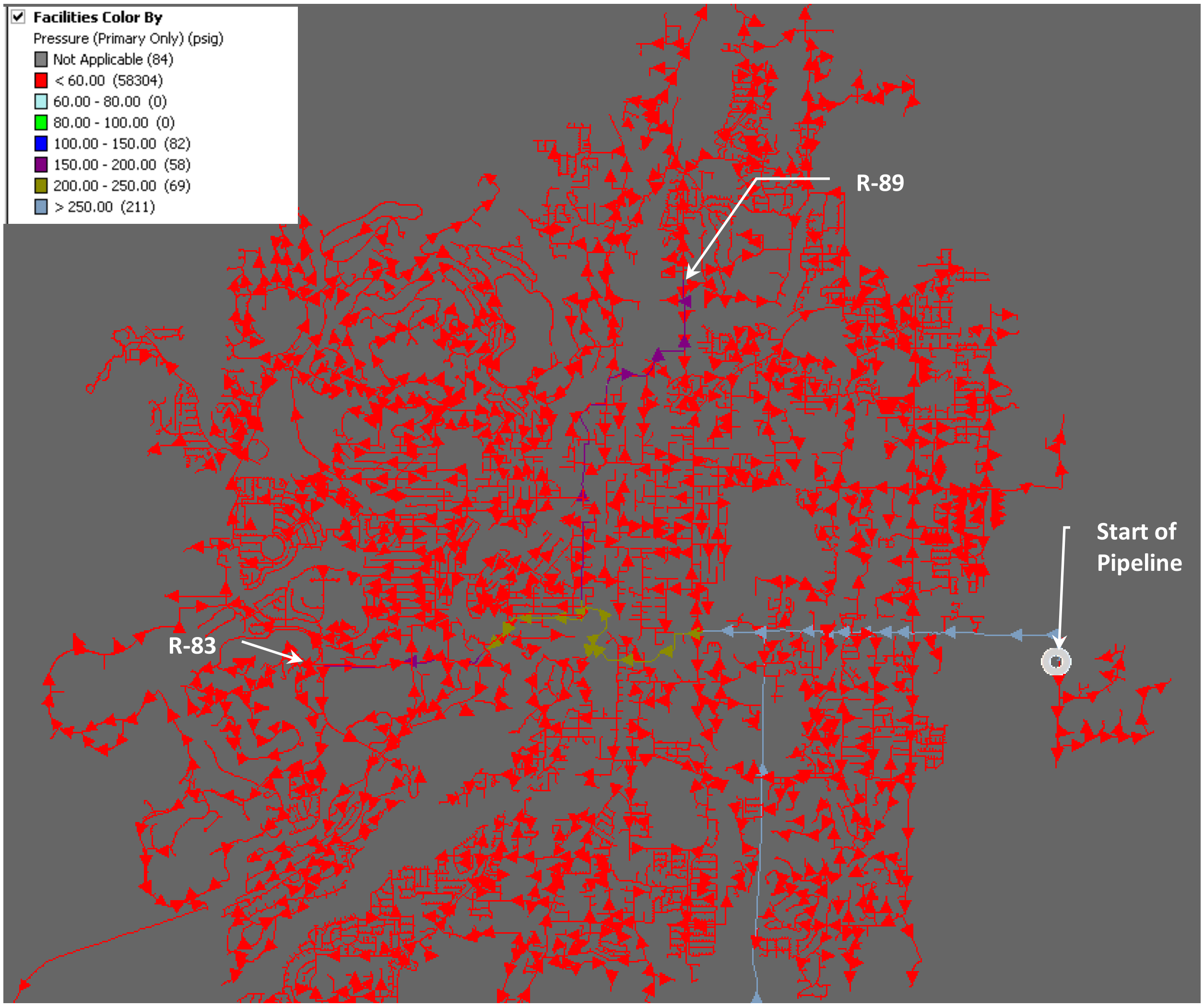
Peak Demand Model - Existing 6"



Peak Demand Model - 8" Replacement



Peak Demand Model - 12" Replacement



b. This project is a high-pressure (HP) replacement and is intended to increase pressure to the outer edges of the HP system. System data has shown inlet pressures to R-83 and R-89 at below 75 psig during certain operating conditions. This low inlet pressure causes the outlet pressures into the distribution system (≤ 60 psig) to drop significantly as a pressure differential (difference between inlet and outlet pressures) is required for a regulator station to function properly and provide the intended distribution system pressure. A loss of 15 psig typically can be experienced when there is a low differential pressure across a regulator station. An increase in the HP inlet pressure, increases the differential across the regulator station, and allows for the distribution system to operate closer to the intended MAOP.

c. This project was not bid out as 6” or 8”, so exact project differences are not exactly known. Decisions were made based on past project experience where 6” and 8” was installed. When it comes to pipe sizing and construction costs the two major contributing factors that impact the overall project cost are material and contractor costs. For material cost the largest cost is the cost of steel pipe. Based on historical pipe orders, costs for steel pipe typically increases around an additional $8 - $10 per foot for each incremental increase in pipe size (4”, 6”, 8”, 10”, 12”). So, for an increase from 6” to 8” material costs would increase approximately $8 - $10 per foot in material costs and an increase from 6” to 12” would increase approximately $16 - $20 per foot. Contractor costs for steel pipe installation will typically increase approximately 10 - 12% to go from 6” to 8” and 18 – 20% to go from 6” to 12”. Contract prices and requirements vary between each project depending on what is required for each project. Pipe size doesn’t typically change these requirements or how a project is constructed but will change the size of equipment and time it takes to complete some tasks for a given project, resulting in the increase in contractor costs. Contractor costs associated with restoration, traffic control, and erosion control typically remain the same and do not typically vary based on pipe size.

AWEC DATA REQUEST NO. 21

Date prepared: July 16, 2020

Preparer: Linda Offerdahl

Contact: Christopher Mickelson

Telephone: (509)-734-4549

AWEC DR 21 TO CASCADE:

Please refer to Cascade's response to AWEC DR 3. Did Cascade generate any budgeting or project management documents for 2019 and 2020 projects other than those provided in response to this request? If yes, please provide these documents.

Response:

No.

AWEC DATA REQUEST NO. 22

Date prepared: July 16, 2020

Preparer: Linda Offerdahl

Contact: Christopher Mickelson

Telephone: (509)-734-4549

AWEC DR 22 TO CASCADE:

Please refer to Cascade's response to AWEC DR 8. The future HP main appears to be a project that has been transferred to plant. Please provide a complete response to AWEC DR 8.

Response:

See updated response below to AWEC DR8:

AWEC DR 8 TO CASCADE:

Please refer to CNGC/200, Darras/14 lines 18 to 20.

a. When was the future HP main transferred to plant in service? 2016.
b. Is the future HP main included in the proposed ratebase for this case? No.
c. If yes, please explain why Cascade considers the future HP main used and useful. N/a.
d. If yes, please provide the gross plant, accumulated depreciation, and depreciation rate for the amounts in ratebase. N/a.

AWEC DATA REQUEST NO. 24

Date prepared: 7/29/20

Preparer: Kevin Conwell

Contact: Christopher Mickelson

Telephone: (509)-734-4549

<u>AWEC DR 24 TO CASCADE</u>:

Please refer to Cascade's cost allocation manual. Please provide all models used to allocate or assign MDU or other affiliate costs to Cascade.

Response:

See attached files:

- AWEC-24 2019 Meter Customer and Employee Counts
- AWEC-24 CNG Cost Allocation Manual 2019
- AWEC-24 Customer Service Group Allocations Page #24
- AWEC-24 Dept 762, 763, 764, 767, 770 Business Services #18
- AWEC-24 Dept 767 Accounts Payable Page #20
- AWEC-24 Dept 941 Dir Finance Allocation Support Pg#29
- AWEC-24 Dept 941 Mgr Revenue Admin Allocation Support Pg#29
- AWEC-24 Dept 941 T Controller Allocation Support Page #29
- AWEC-24 EIT Department Allocation Worksheet page #20
- AWEC-24 Other SS dept allocation 01_19 Final
- AWEC-24 UGFA SLD's Accounting Methodology Pg #29

Cascade Natural Gas

Cost Allocation Manual

2019

CASCADE
NATURAL GAS
CORPORATION
A Subsidiary of MDU Resources Group, Inc.

In the Community to Serve®

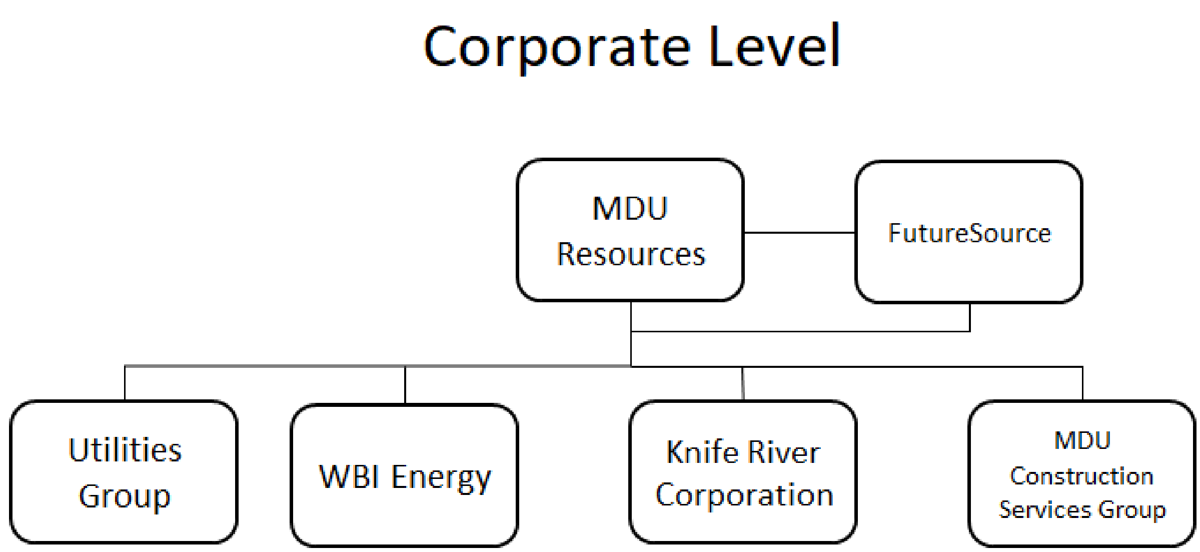
Table of Contents

Overview

Cascade Natural Gas Corporation (CNG), a gas distribution company operating in the states of Washington and Oregon, is a subsidiary of MDU Resources Group, Inc. Cascade Natural Gas has its' own set of financial records. The operations of Cascade Natural Gas Corporation are under the direction of one Utility Group (UG) executive leadership team.

FutureSource Capital Corporation (FutureSource) is a separate legal entity that owns the corporate campus facilities that house the MDUR corporate staff and other property utilized in providing services to the operating companies within MDUR.

Below is an overview of the operational structure for the purpose of assigning costs. The diagram presented is intended to provide an overview for cost allocation only and is not intended to represent the legal structure of the Corporation. Note that costs from MDUR and FutureSource are directly assigned or allocated and charged to the operating companies (i.e. Utilities Group, WBI Energy, etc.)



This document is intended to provide an overview of the different types of allocations and the processes employed to direct costs to CNG.

This document will discuss the allocations to/from:

- MDUR and FutureSource to Cascade Natural Gas Corporation
- Montana-Dakota/Great Plains to Cascade Natural Gas Company (CNGC) and Intermountain Gas Corporation (IGC)
- Cascade Natural Gas Corporation (CNG) to Intermountain Gas Company (IGC) and Montana-Dakota/Great Plains
- Utility segment to state jurisdictions

Overall, the approach to allocating costs at each level is to directly assign costs when applicable and to allocate costs based on the function or driver of the cost.

MDU Resources Group, Inc. (MDUR) Allocations

The MDUR corporate staff consists of shared services departments (payroll, human resources, business services and enterprise information technology), and administrative and general departments.

Shared Services

MDU Resources Group, Inc. has several departments that provide specific services to the operating companies. These departments have developed a pricing methodology which is updated annually for the allocation of costs to the MDUR operating companies that utilize their services. (See Exhibit IV) These departments include:

Payroll Shared Services

Payroll Shared Services department provides comprehensive payroll services for MDUR companies and employees. It processes payroll in compliance with appropriate federal, state and local tax laws and regulations. Payroll Shared Services is also responsible for preparation, filing and payment of all payroll related federal, state and local tax returns. It also maintains and facilitates payments and accurate reporting to payroll vendors for employee benefits and other payroll deductions. For Montana-Dakota and Great Plains, the payroll shared services department is also responsible for the accumulation of time entry records and maintenance of employee records. Montana-Dakota and Great Plains do not have any departments that provide these payroll related services.

Human Resources

Human Resources operates as "One HR" across the regulated business units of MDU Resources Group including Montana-Dakota, Great Plains, Cascade Natural Gas, Intermountain Gas, and WBI Energy. There are employees in the HR departments at each of the business units that focus on the operational function of human resources: employee relations, labor relations, staffing, and leave management, all for their specific location. At MDU Resources, shared HR functions are performed for all of the regulated businesses: compensation management, benefits administration, policy development, human resource information systems, organizational development, as well as providing support and backup for the business unit functions.

Business Services

Business Services provides support services for facilities and administrative services (including bill printing), supply chain (purchasing and inventory), fleet, travel, and accounts payable (including unclaimed property). Business Services also creates and maintains the Corporation's national accounts for the purchase of products, goods and services. National accounts take advantage of the combined purchasing power of all the Corporation's operating companies. Business Services is committed to serving its customers by providing timely, standardized, cost-effective goods and services that support business strategies and goals.

Enterprise Information Technology

Enterprise Information Technology (EIT) provides policy guidance, infrastructure related IT functions and security-focused governance. EIT seeks to increase the return on investment in technology through consolidation of common IT systems and services, while eliminating waste and duplication. EIT works to increase the quality and consistency of technology, increase functionality and service to the enterprise, provide governance for managing and controlling risk and reduce costs through economies of scale.

The EIT services get allocated to Montana Dakota using agreed upon formulas based on utilization of the services.

General and Administrative Services

Administrative and general functions performed by MDUR for the benefit of the operating companies include the following departments:

- Corporate governance, accounting & planning
- Communications & public affairs
- Human resources
- Internal audit
- Investor relations
- Legal
- Risk management
- Tax and compliance
- Treasury services

Administrative and general function performed by MDU for the benefit of the utility group include the following departments:

- Corporate governance, accounting & planning
- Customer Service
- Engineering
- Gas Supply
- Human Resources
- Information Technology
- Safety Management

Cascade Natural Gas Corporation receives an allocation of these corporate costs. Corporate Policy No. 50.10 states "*It is the policy of the Company to allocate MDU Resources Group, Inc.'s (MDU) administrative costs and general expenses to the MDU's business units*". Business units described in the policy have been referred to as operating companies in this document. The policy states that costs that directly relate to a business unit will be directly assigned to the applicable business unit and only the remaining unassigned expenses will be allocated to the operating companies using the corporate allocation methodology. The allocation factor developed to apportion MDUR's unassigned administrative costs is a capitalization factor which is based on 12 month average capitalization at March 31, effective July 1 and at September 30, effective January 1 each year. MDUR has a mix of regulated and non-regulated companies. The non-regulated companies are cyclical in nature and could be impacted significantly with a downturn in the economy. It is unlikely during that same downturn their share of corporate costs would be materially different. Due to the volatility of non-regulated companies, and inconsistency between periods of other potential allocation factors, capitalization is the most appropriate allocation factor for MDUR. Capitalization includes total equity and current and non-current long-term debt (including capital lease obligations). The computation of the Corporate Overhead Allocation Factors is shown in Exhibit I.

Cascade Natural Gas is reflected in the Corporate Overhead Allocation Factors in **Exhibit I**. Operating companies that receive allocated costs on a monthly basis from MDUR include:

- Montana Dakota – Electric utility segment
- Montana Dakota/Great Plains – Gas utility segment
- Cascade Natural Gas Corporation (CNGC)
- Intermountain Gas Company (IGC)
- WBI Energy Transmission
- WBI Midstream
- Knife River (KR)
- MDU Construction Services Group, Inc. (CSG)

Corporate costs are recorded in the administrative and general (A&G) function for Cascade Natural Cas Corporation.

FutureSource

FutureSource, a separate legal entity, owns the facilities at the corporate campus that house the MDUR corporate staff and other property utilized in providing services to all the operating companies within MDUR. These include the corporate office, computers, telephones, furniture, fixtures and aircraft. Montana-Dakota/Great Plains acquired an interest in a portion of the land, building, hangar and aircraft with a cash contribution to FutureSource and placed these assets into rate base. Montana-Dakota/Great Plains receives a cost of service return from CNG and IGC for their proportionate share of the contribution made by Montana-Dakota. The revenue received by Montana-Dakota for this cost of service is recorded in miscellaneous revenue.

Annually, FutureSource calculates a cost of service for any unfunded portion of these corporate assets and invoices the operating companies on monthly basis.

Components included in the cost of service for these facilities and other property include operation and maintenance expenses, depreciation, property taxes, income taxes and a pre-tax return on investment. The annual calculation is maintained by FutureSource and the most recent copy may be requested from the MDU Resources Corporate Planning Department.

FutureSource also owns and operates a corporate aircraft and a hangar. Fixed costs for the aircraft are allocated to the MDUR operating companies on the MDUR corporate overhead factor referenced above (Exhibit I). The variable costs are charged to the appropriate business unit as a direct charge on an hourly flight rate. These charges will at times exceed or be below the actual variable cost. A year-end true-up includes an adjustment to the excess or shortfall in such hourly billing. Flights for employees of Montana-Dakota/Great Plains are directly assigned to the appropriate utility segment and state jurisdiction based on the purpose of the trip. For trips that are not directly applicable to a utility segment/jurisdiction, costs are allocated on the employee's standard payroll allocation and subsequently allocated to the jurisdictions. Standard labor distribution allocations are discussed on page 18.

Cascade Natural Gas Corporation Allocation of Cost to/from Others

Allocations to/from other MDUR Companies

Certain Montana-Dakota/Great Plains owned assets, such as the General Office/Annex facility, located at the utility headquarters in Bismarck, and the assets associated with the contribution made for FutureSource assets, are also used for the benefit of other MDUR operating companies. To cover the cost of ownership and operating costs associated with these owned assets, a revenue requirement (asset return plus annual operating expenses) is computed for the shared assets. The expense component included in the return is composed of operating and maintenance costs, depreciation, income tax and property tax expenses. The resulting revenue requirement is billed to the other MDUR operating companies, including CNGC and IGC, as a monthly fee.

Intermountain Gas owns the customer care center located in Meridian, ID. To cover the cost of ownership associated with that owned asset, a revenue requirement (asset return) is computed similarly to Montana-Dakota owned assets. The expense component included in the return is composed of operating and maintenance costs, depreciation and income tax expense. The resulting revenue requirement is billed to the Montana-Dakota/Great Plains and Cascade as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Additionally, a portion of the cost ownership of the Kennewick General Office is billed to Montana-Dakota/Great Plains and Intermountain Gas Company based on office space occupied by shared utility group employees. The expense component included in the return is composed of depreciation, operating expense and income tax.

The resulting revenue requirements are billed to the Montana-Dakota/Great Plains and Intermountain Gas Company as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Additionally, some expenses are allocated or directly assigned at the invoice/PO or credit card purchase stage.

Allocations to other Utility Companies

Montana-Dakota/Great Plains has several departments that provide services to all four utility operating companies (Montana-Dakota, Great Plains, Cascade Natural Gas Co. and Intermountain Gas Company). These departments include:

- Leadership Group - composed of the Executive Group and Directors that oversee shared utility specific functions
- Customer Services - (Call Center, Scheduling and Online Services)
- Operations & Engineering Services Group – composed of shared utility group operations department functions
- Information Technology and Communications- (Enterprise Network & Telecommunications, Enterprise Management, Enterprise Development and Integration, Field Automation, Enterprise GIS)
- Environmental
- Safety & Technical Training
- Business Development
- Gas Supply & Control
- Utility Group Controller

These operational groups have calculated the proper allocation to use to allocate the costs to the utility companies based on services performed for each utility company. The allocation methodology is included in Exhibit V.

Cascade Natural Gas Corporation's Allocations to Utility Segments

Revenues

All sales and transportation revenues are directly assigned to the appropriate state jurisdiction. Miscellaneous service revenue, rent and other revenue is directly assigned to the utility jurisdiction where possible and common derived revenue is allocated to the utility jurisdiction based on the reason for which the revenue was received.

O&M Expense

As operation and maintenance costs are incurred, the expense is directly assigned to the appropriate state jurisdiction in the general ledger where possible. Expenses incurred that are common to both jurisdictions, such as administrative and general costs, are split between jurisdictions based on the function and/or driver of the cost.

Facility Expense Allocations

Costs for operations and maintenance of facilities are charged directly to the applicable utility jurisdiction when the facility is for the benefit of one jurisdiction.

For expenses associated with distribution operation facilities, such as a region office that serves more than one utility jurisdiction, the costs are allocated to the utility jurisdiction based on the current year 3-factor formula.

Labor / Reimbursable expense allocations

The development of standard labor distributions for Cascade Natural Gas employees is described below based on the type of employee. Standard labor distributions are used for all employees to account for certain expenses as detailed below.

Labor, benefit costs and reimbursable expenses are directly assigned to a utility jurisdiction where possible. If the expense is not direct, the appropriate utility segment is charged as follows:

Union Employees

Time tickets are required for productive time. The employee specifies the proper utility segment, location and FERC account based on work performed. To account for non-productive time, standard payroll labor distributions are established for all employees. These standard labor distributions are calculated for union employees based on the historical actual charges by utility segment for the last 12 months.

Non-Union Employees

Non-union employees are not required to submit detailed time tickets with applicable general ledger accounts specified. Rather each employee has a "standard" set of general ledger accounts that split the labor costs to utility jurisdiction based on an expected ratio of work between jurisdictions. This split can be unique and is based on the employee's position. Costs are distributed based on this standard labor distribution for each employee, and the allocations are reviewed annually. Time studies are completed at least every five years.

- Payroll allocations for operations supervisors are a function of their direct reports or may be determined by time studies conducted.
- Payroll allocations for staff engineers are determined by time studies.
- Payroll allocations for General Office support staff are reviewed by the applicable department head based on the type of work performed.

Reimbursable employee expenses are directly assigned to a utility jurisdiction and FERC account when possible. For employee expenses that are applicable to more than one utility jurisdiction, such as training that is not specific to a utility segment, the employee's standard labor distribution percentages for each segment are used.

Taxes Other than Income

Ad valorem taxes are reviewed by function and all functions are directly assigned except for common ad valorem taxes, which follow plant. Payroll related taxes follow the allocation of labor and revenue and electric production taxes are directly assigned. Common taxes other than income, such as the Highway Use tax or Secretary of State filing tax are allocated on the appropriate factor to the segments.

Income Taxes

Income taxes, both current and deferred, are allocated to the utility jurisdiction based on the underlying revenue or expense that generated the deferred taxes.

If the underlying income item is specific to a particular jurisdiction, the related taxes are assigned directly to that jurisdiction. If the underlying income item is common to both jurisdictions, the related taxes are allocated with factors used to allocate the underlying revenue or expense.

Plant in service / work in progress / reserve / depreciation

Plant in service, work in progress, reserve and depreciation expense accounts are assigned to a utility jurisdiction based on the function of property. For property that benefits both utility jurisdictions an allocation process is used.

The allocation process is based on the combination of the location of the asset and the FERC account (function) that is used to allocate the project, asset, reserve and depreciation.

Prepayments

Prepaid demand and commodity charges are directly assigned to the applicable utility jurisdiction. Prepaid insurance is directly assigned where possible and common policies are allocated based on the type of policy.

Customer Advances

Customer advances are directly assigned to the applicable jurisdiction.

Other rate base items

Where possible, these items are directly assigned to the applicable utility jurisdiction. Common items are allocated based on the cost driver for each item.

Cascade Natural Gas Corporation's Allocations to State Jurisdictions

Cascade Natural Gas utilizes an automated allocation process each month to record the income statement and rate base account activity to the financial ledger (state jurisdiction) to facilitate regulatory reporting. This process is based on the general ledger account structure used in the financial software (JD Edwards). As with other items, costs are directly assigned to a jurisdiction when possible. Costs common to more than one state jurisdiction are allocated between jurisdictions. The primary driver of the allocation is the Business Unit component of the general ledger account; however, the FERC account associated with the charge is also used to determine the proper allocation method. Since operation and maintenance costs are assigned to the utility jurisdiction as incurred, this process only allocates costs between state jurisdictions. The allocation process creates a Journal Entry to the JD Edwards jurisdictional ledgers established by state and utility jurisdiction.

The allocation methodology is as follows:

The JD Edwards (JDE) software is used by Cascade Natural Gas for recording financial transactions as well as the jurisdictional allocation process for all accounts except those related to fixed assets.

The account structure within JDE consists of the following components:

Business Unit **-** The Business Unit is one of the primary components used for identifying the regulatory allocation of costs. It usually defines a location such as an operating region, operating district or facility, gas regulator station, or department (i.e. human resources, engineering).

Object **–** The object for operations and maintenance (O&M) expense accounts represents the resource consumed (i.e. payroll or materials). For balance sheet accounts, the object represents the FERC account.

Subsidiary **–** The subsidiary portion of the account for O&M accounts identifies the utility segment and the FERC account. For balance sheet accounts the subsidiary represents a further breakdown of the account such as which bank for a cash account.

Revenue Accounts – Revenues are directly assigned to the jurisdiction when possible. The applicable FERC account is part of the account structure and in the case of utility billed revenue the utility jurisdiction is included. It is the combination of the business unit, utility segment and FERC that drive the allocation factor used. An example of revenue that is allocated to the jurisdictions is revenue from the cost of service calculation which is assigned an allocable location (Business Unit).

Operation and Maintenance (O&M) accounts – As costs are incurred, the approver of the expense assigns the general ledger account structure.

It is the combination of the location (Business Unit), utility jurisdiction and FERC that drive the allocation factor utilized. Locations are assigned a factor based on the geographic area for which they serve and the FERC function assigned. For example, location (Business Unit) 230 represents the geographic location of the Sheridan, WY District. The Sheridan District serves both electric and gas and is therefore directly assigned to Wyoming for all FERC accounts. Another example is location 12900, representing the Credit and Collections Department. The Credit and Collections Department services both the electric and gas customers. The allocation of costs is based on the FERC range of accounts. The location may also be a responsibility, or department.

Location	Location Description	Sub 1	Sub 2	Utility Segment	Utility Alloc Code	Utility Allocation Description	Utility Allocation Rate	Juris Alloc Code	Juris Allocation Description	Juris Allocation Rate	Combined Effective Rate
230	Wyoming District	1560	15709999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00005	WYOMING ONLY	100.000000%	100.000000%
230	Wyoming District	1580	19359999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00005	WYOMING ONLY	100.000000%	100.000000%
12900	Credit & Collections	1920	19359999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00026	O&M EXCLUDING FUEL & PURCHASED POWER & A&G	8.336614%	8.336614%
12900	Credit & Collections	1901	19169999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00085	TOTAL COMPANY ELECTRIC CUSTOMER COUNT	11.315965%	11.315965%
12900	Credit & Collections	1580	15989999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00118	ELECTRIC DISTRIBUTION PLANT	14.798583%	14.798583%

*Co	*Location	*Obj Acct	*FERC Sub 1	*FERC Sub 2	*Start Date	Stop Date	Description	Utility Alloc Code	Utility 01	Allocation Code 01
00001	230		1560	15709999	199703	203512	Wyoming District	00001	1	00005
00001	230		1580	19359999	199501	203512	Wyoming District	00001	1	00005
00001	230		28120	28120	199703	203512	Wyoming District	00002	2	00005
00001	230		2870	29359999	199501	203512	Wyoming District	00002	2	00005

00001 code = 100 % Electric

00002 code = 100 % Gas

Code 00005 = 100% allocated to WY

*Co	*Location	*Obj Acct	*FERC Sub 1	*FERC Sub 2	*Start Date	Stop Date	Description	Utility Alloc Code	Utility 01	Allocation Code 01
00001	12900		1580	15989999	200910	203512	Credit & Collections	00001	1	00118
00001	12900		1901	19169999	200501	203512	Credit & Collections	00001	1	00085
00001	12900		1920	19359999	200501	203512	Credit & Collections	00001	1	00026
00001	12900		2870	28949999	200910	203512	Credit & Collections	00002	2	00119
00001	12900		2901	29169999	200501	201508	Credit & Collections	00002	2	00086
00001	12900		2901	29169999	201509	203512	Credit & Collections	00002	2	00087
00001	12900		2920	29359999	200501	203512	Credit & Collections	00002	2	00027

Utility Allocation Code
Represents the code used to allocate costs to a business segment
00001 = Electric segment
00002 = Gas segment

Allocation code 01
Represents the code used to allocate costs to a Jurisdiction
00118 = Electric distribution plant
00085 = Total company electric customer count
00026 = O&M excluding fuel & purchased power and A&G
00119 = Gas distribution plant
00087 = Total company gas sales customer count
00027 = O&M excluding cost of gas and A&G

Taxes Other Than Income

Taxes other than income taxes are directly assigned when possible. Ad valorem taxes are allocated based on the subsidiary, which indicates the jurisdiction and function. Payroll related taxes follow the allocation of labor, revenue taxes are directly assigned and generation and other taxes are allocated on the applicable factor.

Income Taxes

Federal taxes that are allocated or directly assigned to the utility jurisdiction are allocated to the jurisdictions based on the factors used to allocate the underlying revenue or expense among the jurisdictions.

State taxes that are allocated or directly assigned to a utility segment, are allocated to the jurisdictions that have state income tax based on their respective state apportionments.

Plant in Service/Work in Progress/Reserve/Depreciation Accounts

Plant in service, work in progress, reserve and depreciation expense accounts are allocated in through a similar process in the PowerPlan software based on attributes associated with the work order and asset.

It is the combination of the utility segment, location of the asset and the FERC account that is used to allocate the project, asset, reserve and depreciation. The tables that are maintained in JDE for jurisdictional allocations are interfaced into PowerPlan and are used to allocate these accounts.

Allocation Factors

The allocation factors are computed annually by the Regulatory Affairs and General Accounting departments and assigned to the proper Business Unit (location) effective in January each year. See Exhibit VI for a list of the allocation factors.

Exhibit I - MDUR Corporate Overhead factor

MDU Resources Group, Inc.
Corporate Overhead Allocation Factor
January - June 2019

	MDU Electric	MDU/GP Gas	CNGC	IGC	WBI Energy Transmission	WBI Energy Midstream	KR	CSG
MDUR Corporate Factor	20.4%	14.0%	14.9%	10.0%	8.3%	0.3%	22.9%	9.2%

MDU RESOURCES GROUP, INC.
12 Month Average Consolidating Balance Sheet
September 2018

	WBI Energy	Knife River	Construction Services	Utilities Group	Consolidated
Debt and Equity					
Short-term borrowings					---
LTD due within one year	1,000,000.00	28,809,524.50	71,239.98	97,035,948.02	126,916,712.50
Long-term debt	184,897,919.53	341,354,594.53	89,118,439.42	1,118,067,733.43	1,733,438,686.91
Total Debt	**185,897,919.53**	**370,164,119.03**	**89,189,679.40**	**1,215,103,681.45**	**1,860,355,399.41**
Stockholders' equity:					
Preferred stocks		---	---	---	---
Common stock	1,000.00	800,000.00	1,000.00	196,082,279.67	196,884,279.67
Other paid-in capital	803,182,762.05	495,748,408.91	134,859,038.50	1,739,022,954.79	3,172,813,164.25
Retained earnings	(586,466,247.50)	123,448,294.30	162,271,164.51	1,081,619,915.31	780,873,126.62
Accumulated other comprehensive income (loss)	(3,158,615.65)	(29,585,480.00)	(2,627,163.98)	(43,006,431.98)	(78,377,691.61)
Treasury stock	---	(3,625,812.59)	---	(3,625,812.59)	(7,251,625.18)
Total common stockholders' equity	**213,558,898.90**	**586,785,410.62**	**294,504,039.03**	**2,970,092,905.20**	**4,064,941,253.75**
Total stockholders' equity	**213,558,898.90**	**586,785,410.62**	**294,504,039.03**	**2,970,092,905.20**	**4,064,941,253.75**
Total liabilities and stockholders' equity	**399,456,818.43**	**956,949,529.65**	**383,693,718.43**	**4,185,196,586.65**	**5,925,296,653.16**
IC Investment in Subsidiaries	---	---	---	1,706,288,626.51	1,706,288,626.51
Fidelity E&P 12 Mth Avg Capitalization	(40,471,854.42)	---	---	---	(40,471,854.42)
Capitalization	**358,984,964.01**	**956,949,529.65**	**383,693,718.43**	**2,478,907,960.14**	**4,178,536,172.23**

	WBI Energy	Knife River	CSG	Utilities Group	Total
MDUR Corporate OH Factor	8.6%	22.9%	9.2%	59.3%	100.0%

	2018 Capitalization (In thousands)	Share of Corp. Allocation	Corporate Allocation	Electric	Gas
Montana-Dakota 1/	$1,465,385	58.0%	34.4%	20.4%	14.0%
Cascade	635,833	25.2%	14.9%		14.9%
Intermountain	425,565	16.8%	10.0%		10.0%
Total Utilities Group	$2,526,783	100.0%	59.3%	20.4%	38.9%

1/ Electric and gas segments allocated on Montana-Dakota's Corporate Overhead Factor

Exhibit II- Montana-Dakota/Great Plains Overhead factor

Montana-Dakota Utilities Co.
Corporate Overhead Allocation Factors
January - June 2019

	Electric	Gas
Montana-Dakota corporate factor	59.2	40.8
Employee factor	42.9	57.1
Plant factor	75.5	24.5
Customer factor	32.6	67.4

Exhibit III- Montana-Dakota/Great Plains Customer Allocation Factors

Montana-Dakota Utilities Co
2019 Customer Allocation Factors

	Customers	% Factor	State % Factor
Montana			
Gas	84,565	0.77	0.20
Electric	25,707	0.23	0.06
	110,272	1.00	0.26
North Dakota	**Customers**	**% Factor**	
Gas	109,365	0.54	0.26
Electric	92,817	0.46	0.22
	202,182	1.00	0.49
South Dakota	**Customers**	**% Factor**	
Gas	60,402	0.88	0.15
Electric	8,547	0.12	0.02
	68,949	1.00	0.17
Wyoming	**Customers**	**% Factor**	
Gas	18,782	0.54	0.05
Electric	15,976	0.46	0.04
	34,758	1.00	0.08
Total Customers	416,161		

Great Plains
Jurisdictional Customer Allocation Factor

North Dakota GPNG	2,275	0.10
Minnesota - GPNG	21,668	0.90
	23,943	1.00

Montana-Dakota Utilities Co
Customer Count Splits for Regions and Districts

Rocky Mountain Region		**Badlands Region**	
MT Gas	65%	ND Elec	36%
WY Elec	16%	ND Gas	23%
WY Gas	19%	MT Elec	22%
		MT Gas	18%
Billings District		SD Elec	1%
All Gas	100%		
Sheridan Dist (#63)		**Reg split (#65)**	
Electric	46%	Electric	59%
Gas	54%	Gas	41%
		Dickinson Dist	
		Electric	58%
Dakota Heartland Region		Gas	42%
ND Elec	34%	***Glendive Dist***	
ND Gas	55%	Electric	56%
SD Elec	5%	Gas	44%
SD Gas	6%	***Williston Dist (#69)***	
		Electric	65%
Region Split (#64)		Gas	35%
Electric	39%	***Wolf Point Dist (#68)***	
Gas	61%	Electric	50%
Bismarck Dist (#86)		Gas	50%
Electric	51%		
Gas	49%		
Mobridge Dist (#14)		**Black Hills Region**	
Electric	58%	SD Gas	100%
Gas	42%		
Jamestown District		***Rapid City District***	
All Gas	100%	All Gas	100%
Minot District		***Spearfish District***	
All Gas	100%	Gas	100%

Customer Allocations by State

GAS		
MT Gas	84,565	31.0%
ND Gas	109,365	40.0%
SD Gas	60,402	22.1%
WY Gas	18,782	6.9%
	273,114	
ELECTRIC		
MT Elec	25,707	18.0%
ND Elec	92,817	64.9%
SD Elec	8,547	6.0%
WY Elec	15,976	11.1%
	143,047	

Exhibit IV- MDUR Shared Services Pricing Methodology

MDU Resources Shared Services
Pricing Methodology - Effective for 2019

Note: Any shared services amount allocated to MDU Resources are charges out to the business units on the corporate allocation factor.

761 – Payroll Shared Services:

Payroll Shared Services costs are invoiced based on the number of employees paid and stated as a cost per check. The word check, for this purpose, generically refers to paper paychecks, direct deposits and pay card transactions.

Checks are charged on a tiered structure, intended to recognize the fixed or baseline effort associated with maintaining a payroll cycle and associated reporting, regardless of number of people paid. It is also intended to reward consolidation of multiple pay groups and companies where possible and to align charges with the additional effort required to maintain multiple pay groups and pay cycles.

The monthly volume for this step pricing is accumulated individually for each pay cycle processed.

Checks for weekly pay cycles, cost per check based on the number of checks written per month:
$ 4.25 per check for the first 500 checks
$ 0.25 per check for the next 500 checks
$ 0.10 per check for each additional check

Checks for non-weekly pay cycles, cost per check based on the number of checks written per month:
$ 4.25 per check for the first 1500 checks
$ 0.25 per check for the next 500 checks
$ 0.10 per check for each additional check

Additionally, there will be a $4.00 charge for each tax payment and $250.00 charge for each quarterly tax filing and $2 charge for each W2

There is a $500 per month minimum charge for each operating company.

There is a premium charge of $50 per transaction for specific off cycle checks and back-pay calculations. Examples of transactions included in the premium charge schedule are missing hours, refunded deductions, length of service awards submitted too late for inclusion in a scheduled payroll process, and back pay calculation because an increase was submitted after the pay period that includes the effective date. Examples of transactions excluded from the premium charge calculation are bonus payments, final paychecks, certified wage settlements, or any payment required as a result of a Shared Service or system error.

766 –Time Entry Shared Services:

Time entry service is provided for the Utility Group and MDU Resources employees based on the average number of employees at each location.

	MDUR	MDU/GP	CNG	IGC	WBIE	KRC	CSG*	Total
Average Number of Employees	205	1,050	365	245				1,865
Total weighted allocation factor	10.99%	56.30%	19.57%	13.14%				100%

* Time Entry Shared Services manually keys time entry for Desert Fire. Payroll Shared Services and Desert Fire agree to use two times the amount of the cost per check rather than a separate time entry charge. The two methods are comparable.

970 – Human Resources:

Human Resources costs for the MDU Resources HR team are based on employees served. The average number of employees at each company for 12 months ending June 30 is calculated, then further broken down to whether they are on the Corporate-held benefit plans and/or retirement plans.

An allocation for each individual HR team member is calculated based on which group(s) of employees they serve. For example, an HR Generalist whose functions serve the Regulated companies would have an allocation to MDUR, MDUG, and WBI. A Benefits Analyst who is responsible for the Health & Welfare plans would have an allocation to the regulated companies as well as KRC and CSG companies who participate in the Corporate plans.

These individual allocations are all combined into one aggregate allocation to be used by all MDUR shared HR employees. The reason for this method is that the same work would need to be absorbed should a vacancy occur. Human Resources has three individuals that are not considered shared services and are allocated on the corporate overhead allocation factor.

	MDUR	MDU/GP	CNG	IGC	WBIE-T	WBIE-M	KRC	CSG	Total
Allocation	4.34%	25.15%	7.60%	5.25%	13.72%	2.61%	22.49%	18.84%	100%

762 –Business Services: ✓
This allocation factor is derived from the results of the following four responsibilities. After allocating the projected (budget) costs for the following four responsibilities to each business unit, based on the weighted allocation factor of each of these four responsibilities, each business unit total is summed and divided by the total cost resulting in the following allocation percentages. Individuals in this responsibility provide oversite and support for the following four responsibilities.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Allocation %	17.66%	32.71%	11.66%	9.55%	0.64%	6.06%	1.48%	12.28%	7.96%	100%

Cost Allocation Manual

763 –Fleet and Travel:

Fleet and Travel Departments costs are invoiced based on five weighted factors from the previous year:

- Travel – based on corporate factor
- Managed Units
- National Account Spend
- Construction Equipment Acquisitions
- Fleet Acquisitions

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
% of Travel Corporate		34.30%	14.40%	12.50%		8.00%	0.40%	21.70%	8.70%	100%
# Managed Units		36	319	223						578
% of Managed Units		6.23%	55.19%	38.58%						100%
National Account Spend	$1,322,570	$18,679,456	$7,681,820	$4,895,822		$6,196,219	$992,764	$132,526,463	$51,797,911	$224,093,025
% of National Account Spend	0.59%	8.34%	3.43%	2.18%		2.77%	0.44%	59.14%	23.11%	100%
# Construction Equip Acquisitions		69	18	9		7	4	108	107	322
% of Construction Equip Acquisitions		21.43%	5.59%	2.80%		2.17%	1.24%	33.54%	33.23%	100%
# Fleet Acquisitions		29	25	29		40	7	166	127	423
% of Fleet Acquisitions		6.86%	5.91%	6.86%		9.46%	1.65%	39.24%	30.02%	100%
Weighted Allocation Factors:										
Travel Corporate	21.70%	The percent of time spent on corporate travel.								
# Managed Units	15.66%	The percent of time spent on managed units.								
National Acct Spend	15.66%	The percent of time spent on national accounts.								
Construction Equip Acquisition	23.49%	The percent of time spent on the acquisition of construction equipment assets.								
Fleet Acquisition	23.49%	The percent of time spent on the acquisition of vehicle assets.								
	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Total weighted allocation factor	0.09%	16.37%	15.00%	11.36%		4.30%	0.84%	31.07%	20.37%	100%

764 –Supply Chain:

There are several individuals that are primarily focused on the Utility Group and some that have multiple business unit responsibilities.

Allocations are based on two weighted factors from previous year:

- Purchase Order Count
- Purchase Order Line Count

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Purchase Order Count	29	4413	908	971		835	252			7,408
% of Purchase Orders	0.39%	59.57%	12.26%	13.11%		11.27%	3.40%			100%
Purchase Order Line Count	44	26,707	2,770	2,858		4,876	1,479			38,734
% of Purchase Order Line Count	0.11%	68.95%	7.15%	7.38%		12.59%	3.82%			100%
Weighted Allocation Factors:										
PO Count	1.00%	The percent of purchase orders processed by Company.								
PO Line Count	99.00%	The percent of lines on purchase orders processed by Company.								
	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Total weighted allocation factor	0.12%	68.86%	7.20%	7.44%		12.57%	3.81%			100%

Cost Allocation Manual

767 –Accounts Payable:

Costs are invoiced based on four weighted factors from previous year:

- Number of Payments
- Number of Vouchers
- Number of Unclaimed Property reports
- Number of PNC payments

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
# of Payments - 8/1/2017 through 8/1/2018	2,133	32,726	20,778	18,433		6,686	2,044		739	83,539
% of Payments	2.55%	39.17%	24.87%	22.07%		8.00%	2.45%		0.89%	100%
# of Vouchers - 8/1/2017 through 8/1/2018	2,497	49,487	32,806	23,596		11,911	3,312		1,525	125,134
% of Vouchers	1.99%	39.55%	26.22%	18.85%		9.52%	2.65%		1.22%	100%
# of States Filed in - as of 5/26/2018		34	17	28		23	3	10	4	119
% of Unclaimed Property		28.57%	14.29%	23.53%		19.33%	2.52%	8.40%	3.36%	100%
# of Companies Implemented - as of 8/1/2018	3	1	1	1		1	1	19	16	43
% of PNC	6.98%	2.32%	2.33%	2.33%		2.32%	2.32%	44.19%	37.21%	100%
Weighted Allocation Factors										
# of Payments	15.00%	The percent of time spent on processing payments, setting up address book records, 1099s, etc.								
# of Vouchers	65.00%	The percent of time spent on vouchering and reviewing invoices								
# of Unclaimed Property	15.00%	The percent of time spent filing unclaimed property reports, sending due diligence letters, defending audits								
# of PNC	5.00%	The percent of time spent with companies that are using PNC to make vendor payments								
	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Total weighted allocation factor	2.00%	36.00%	23.00%	19.20%		10.40%	2.60%	3.50%	3.30%	100%

770 –Buildings and Grounds:

This allocation is based on labor hours spent by location from the previous year

	MDUR	MDU/GP	CNG	IGC	WBIE	KRC	CSG	Total
Allocation %	43.00%	50.00%			4.00%	3.00%		100%

Enterprise Information Technology (EIT):

There are several EIT departments, and each is billed out based on its own criteria. They are as follows.

Application Services (765) – The allocations will be based on time tracked history for the 12 months of the prior year. The MDUG portion is further divided by meter count and the WBI portion is further divided by the WBI corporate factor.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
12-month work load	3,977	2,955	1,944	2,347		970	103	1,234	237	13,767
% of 12 mon work load	28.89%	21.46%	14.12%	17.05%		7.05%	0.75%	8.96%	1.72%	100%

Definition of 765: This team is made up of software developers providing integrations to systems and software changes.

Operational Technology (768) –The allocations are based on projected work load. This department is 100% direct allocated based on the projects assigned.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Projected Hours	661	5,579								6,240
% of 12 mon work load	10.60%	89.40%								100%

Definition of 768: This team is made up of security and infrastructure technicians.

Cost Allocation Manual

Customer Relations (965) – Enterprise charges for the customer relations group are invoiced using three weighted allocation factors. The factors are as follows:

1. Direct charge for employees working for a specific business
2. Number of computing devices supported by the help desk (90%)
3. Number of mobile devices supported by the help desk (10%)

The metric used to determine device counts is devices that have checked into active directory during a 60-day period in the summer of 2018 and active devices in MobileIron.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Direct Charges			53.53%	46.47%						100%
Factor- 13.49%			7.22%	6.27%						13.49%
Computing Device Counts	313	1,266	509	653	54	309	46	1,885	1,798	6,833
% of Device Count	4.58%	18.53%	7.45%	9.56%	0.79%	4.52%	0.67%	27.59%	26.31%	100%
% of Device Factor- 77.86% (86.51% x 90%)	3.57%	14.42%	5.80%	7.44%	0.62%	3.52%	0.53%	21.48%	20.48%	77.86%
Mobile Device Counts	159	561	277	195	207			1,866	2,410	5,675
% of Device Count	2.80%	9.89%	4.88%	3.43%	3.65%			32.88%	42.47%	100%
% of Device Factor- 8.65% (86.51% x 10%)	0.24%	0.86%	0.42%	0.30%	0.32%			2.84%	3.67%	8.65%
Total weighted allocation factor	3.81%	15.28%	13.44%	14.01%	0.94%	3.52%	0.53%	24.32%	24.15%	100%

Definition of 965: This team is made up of help desk agents who support company owned devices and software.

Communications (971)

Enterprise charges for the communications group are invoiced using four weighted allocation factors. The factors are as follows:

1. Direct charge for employee hours working for a specific business (10.53%) (MDUG portion is split by meter count).
2. Wide Area Network/Local Area Network/Metropolitan Area Network- Number of business unit locations (35.79%)
3. Internet/Firewall Access – Number of computing devices (35.79%)
4. IP Telephony (17.89%)

The costs are invoiced based on the following percentages:

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Direct Charges		40.78%	26.83%	32.39%						100%
Factor- 10.53%		4.29%	2.83%	3.41%						10.53%
WAN/LAN/MAN	7	61	19	13	1	142	3	222	76	548
% of Business Unit Locations	1.28%	11.13%	3.47%	2.37%	0.18%	26.28%	0.55%	40.51%	14.23%	100%
Factor- 35.79%	0.46%	3.98%	1.24%	0.85%	0.06%	9.41%	0.20%	14.50%	5.09%	35.79%
Internet Access/Firewall	313	1,266	509	653	54	309	46	1,885	1,798	6,833
% of User Accounts	4.58%	18.53%	7.45%	9.56%	0.79%	4.52%	0.67%	27.59%	26.31%	100%
Factor- 35.79%	1.64%	6.63%	2.67%	3.42%	0.28%	1.62%	0.24%	9.87%	9.42%	35.79%
IP Telephone	256	822	435	389		269	35	1,747	177	4,130
% of Handsets	6.20%	19.90%	10.53%	9.42%		6.51%	0.85%	42.30%	4.29%	100%
Factor- 17.89%	1.11%	3.56%	1.88%	1.69%		1.16%	0.15%	7.57%	0.77%	17.90%
Total weighted allocation factor	3.21%	18.46%	8.62%	9.37%	0.34%	12.19%	0.59%	31.94%	15.28%	100%

Definition of 971: This team supports the wide area network and phones. This includes switches, routers and firewalls

Cost Allocation Manual

Operations (972) – Enterprise charges for the operations group are invoiced using three separate factors

(1) 18.12% are direct charges that are costs directly related to the AS/400 computer and are invoiced upon the AS/400 allocation as agreed to by MDU and WBI.

The remaining 81.88% of the costs are based upon the number of servers that are supported for each business unit. These servers are then broken out between full service servers and shared service servers. Full service servers have a greater weighting factor since they require more dedicated time and cost more

(2) Full Service Servers - 61.41% (81.88% x 75%)

(3) Shared Service Servers 20.47% (81.88% x 25%).

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Direct Charges	4.93%	39.76%	22.80%	23.85%	8.34%				0.32%	100%
Factor- 18.12%	0.90%	7.20%	4.13%	4.32%	1.51%				0.06%	18.12%
Full Service Servers	240	84	1	2	32	5		133	36	533
% of Full Service Servers	45.03%	15.76%	0.19%	0.38%	6.00%	0.94%		24.95%	6.75%	100%
Factor- 61.41%	27.65%	9.68%	0.12%	0.23%	3.69%	0.58%		15.32%	4.14%	61.41%
Shared Service Servers		131	38	92		31	3	49	105	449
% of Full Service Servers		29.18%	8.46%	20.49%		6.90%	0.67%	10.91%	23.39%	100%
Factor- 20.47%		5.97%	1.73%	4.19%		1.41%	0.14%	2.24%	4.79%	20.47%
Total weight allocation factor	28.55%	22.85%	5.98%	8.74%	5.20%	1.99%	0.14%	17.56%	8.99%	100%

Definition of 972: This team is responsible for administration of the enterprise servers.

Security (977) – Enterprise charges for the security group are distributed via the number of computing devices (90.00%) and mobile devices (10.00%). Costs are invoiced based on the following percentages:

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Computing Device Counts	313	1,266	509	653	54	309	46	1,885	1,798	6,833
% of Device Factor- 90%	4.12%	16.67%	6.70%	8.60%	0.72%	4.07%	0.61%	24.83%	23.68%	90.0%
Mobile Device Counts	159	561	277	195	207			1,866	2,410	5,675
% of Device Factor- 10%	0.28%	0.99%	0.49%	0.34%	0.36%			3.29%	4.25%	10.0%
Total weighted allocation factor	4.40%	17.66%	7.19%	8.94%	1.08%	4.07%	0.61%	28.12%	27.93%	100%

Definition of 977: This team supports the cyber security initiatives.

ERP (956) – Enterprise charges for the ERP group are being allocated based on 12 months of the prior year hours worked in JIRA. The costs are invoiced based on the following percentages:

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
12-month work load	927	885	362	196	1,064			277		3,711
% of 12 mon work load	24.98%	23.84%	9.76%	5.29%	28.67%			7.46%		100%

Definition of 956: This team supports the accounting software.

Scada (968) – Enterprise charges for the SCADA group are being allocated based on 12 months of the prior year of hours worked in JIRA. The costs are invoiced based on the following percentages:

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
12-month work load		444	438	528		2,707				4117
% of 12 mon work load		10.78%	10.64%	12.83%		65.75%				100%

Definition of 968: This team supports the gas SCADA systems.

Governance (982) –. Costs for the governance and administration group are invoiced based on a weighting of the combined methodologies of the eight previous EIT responsibilities

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
2019 % of Total Governance & Administration	15.73%	22.88%	9.23%	10.66%	3.24%	7.76%	0.44%	18.66%	11.40%	100%

Exhibit V- Utility Operations Support Allocation Methodology

Leadership Group:

President & CEO (985) – The payroll allocations will be based on average Utility Group customer and employee counts for the President & CEO and Executive Assistant.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Customer Counts	118,169	245,530	293,376	365,744	1,022,819
% of Factor – 50%	5.75%	12.03%	14.34%	17.88%	50%
Utility Group Employee Counts	431	573	338	242	1,584
% of Factor – 50%	13.60%	18.10%	10.65%	7.65%	50%
Total weighted allocation factor	19.4%	30.1%	25.0%	25.5%	100%

Executive Vice President of Business Development & Gas Supply (701) – The payroll allocations will be based on Utility Group customer counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Customer Counts	11.5%	24.0%	28.7%	35.8%	100%

Vice President of Safety, Process Improvement & Operations Systems (707) – The payroll allocations will be based on Utility Group meter counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%

Executive Vice President of Regulatory Affairs, Customer Service & Administration (919) – The payroll allocations will be based on meter counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%

Vice President of Operations & Engineering Service (960) – The payroll allocations will be based on Utility Group customer counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Customer Counts	11.5%	24.0%	28.7%	35.8%	100%

Customer Service Group:

The Customer Service group is made up of four distinct areas and provides service to all four brands within the MDU Utility Group. Those areas are Credit and Collections, Scheduling, Customer Service, and Customer Programs and Support. In addition to these departments, the Customer Service group has a management team, Consumer Specialists, and other administrative positions. Customer Service payroll costs are allocated using five (5) different methodologies: Customer Count, Customer Call Time, Cleared Order Count, Credit To-Dos, and Emails and Web Requests. Costs other than payroll will be allocated based on customer count if they provide benefit for all brands. Costs specific to a brand will be charged directly to that brand and will not go through an allocation process.

Customer Count

- Based on the average customer count of each utility brand from December to November.
- Uses a customer weighting of 1 for each natural gas or electric only customer and 1.25 for each electric/natural gas combination customer.
- The following positions will be allocated based on customer count ***with nonutility***:
    - Customer Service Director
    - Manager, Customer Service
    - Supervisor, Customer Service
    - Customer Service Trainer
    - Customer Service Team Lead (Support)
- The following positions will be allocated based on customer count ***without nonutility***:
    - Administrative Assistant
    - Customer Service Team Lead (Credit)
    - Customer Project Analyst I and II
    - Supervisor, Scheduling & Customer Support
    - Manager, Customer Service & Credit
    - Customer Communications Coordinator
    - Supervisor, Credit & Collections
    - Manager, Scheduling, Support, Prgm
    - Scheduling Analyst
    - Scheduling Lead

Customer Call Time

- Based on the total time that Customer Service Agents are handling a call.
    - Includes total talk time and after call work
    - Does not include idle time or auxiliary time
- Uses data for the preceding December to November of each year.
- The following positions will be allocated based on customer call time:
    - Customer Service Rep I, II, III, IV, and IV PT

- ***Cleared Order Count***
    - Based on the number or work orders cleared through the work assignment management system for each brand.
    - Uses data for the preceding December to November of each year.
    - The following positions will be allocated based on cleared order count:
        - Scheduler

- ***Credit To-Do's***
    - Based on three types of completed To-Do's;
        - accounts up for severance

    - closed accounts pending write-off
    - broken payment plans
- Uses data for the preceding December to November of each year.
- The following positions will be allocated based on credit to-do's:
    - Credit & Collections Rep I, II, and III
    - Credit Support Rep

- ***E-mails and web requests***
    - Based on e-mails that include direct inquiries from customers, follow up requests from a CSR phone call, or e-mails generated by the web applications requiring account maintenance.
    - Uses data for the preceding December to November of each year.
    - The following positions will be allocated based on e-mails
        - Customer Support Rep I, II, and III

	MDU Elect	MDU/GP Gas	MDU Nonutility	CNG	IGC	Total
Customer Counts	11.82%	24.51%	.74%	28.1%	34.83%	100%
Customer Counts	12.06%	25.01%	-	28.1%	34.83%	100%
Customer Call Time	12.49%	25.9%	-	27.9%	33.71%	100%
Cleared Order Count	10.48%	21.91%	-	35.88%	31.73%	100%
Credit To-Dos	15.53%	32.21%	-	19.63%	32.63%	100%
Emails	10.05%	20.85%	-	30.92%	38.18%	100%

<u>Operations & Engineering Services Group:</u>

Process Improvement & Operations Tech (Dept 703)
The payroll allocations will be based on the Utility Group employee counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Employee Counts	27.2%	36.2%	21.3%	15.3%	100%

Quality Control (Dept 730)
The Quality Control department provides oversight and post work review of both maintenance and construction work that is performed by both utility group employees and our contractors. The payroll allocations will be based on time studies.

Engineering Services (Dept 769)
The Engineering Services department duties include gas modeling, working with district personnel, engineering design of capital projects, creation of cost estimates, creation of design and work plans, budget planning, etc. The payroll allocations will be based on time studies.

Construction Services (Dept 863)
The Construction Services (CS) department provides construction management and inspection for large and high-pressure projects, as well as for projects generated by TIMP, DIMP, and MAOP Validation Plans. CS creates and manages programs and procedures for welding and fusion programs. Fabrication standards and a majority of fabrication are done by CS. The payroll allocations will be based on time studies.

Operation Systems (Dept 864)
This department supports Operations compliance systems as well as supporting other systems that Operations and Engineering utilize. The group not only supports these efforts but also works as a liaison group between the business and enterprise information technology (EIT). The payroll allocations will be based on time studies. Costs specific to a brand will be charged directly to that brand and will not go through an allocation process.

System Integrity (Dept 865)
The System Integrity department is responsible for the Utilities Distribution and Transmission Integrity Management Programs, Integrity Projects, Cascade's MAOP Validation Project, and Corrosion Control. The payroll allocations will be based on time studies.

Safety Management System & Quality Assurance (Dept 866)✓
The Safety Management System and Quality Assurance (SMS/QA) department is responsible for the implementation of the utility group's safety management system. The team is responsible for reviewing, documenting, and developing processes to ensure compliance with the industry recommend practice 1173. Key objectives of our current plan include the development of an operational risk management program, SMS/QA program oversight and metrics, and completion of risk-based process audits. The payroll allocations will be based on Utility Group gas customer count.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Gas Customer Counts	-	31.2%	30.6%	38.2%	100%

Operations Policies & Procedures (Dept 923)
This department is responsible for aligning new Utility Group procedures as well as maintaining all previous company specific procedures. Each company was and is required to have and maintain these procedures per federal code 192. The payroll allocations will be based on an equal share across the gas segments.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Allocation %	-	34.0%	33.0%	33.0%	100%

Operation Services (Dept 958)
The Operation Services department provides compliance, damage prevention, and public awareness across the Utility Group. The payroll allocations will be based on time studies.

<u>Information Technology and Communications Group:</u>

Enterprise Network & Telecommunications (Dept 721)
This department processes bill payment files, provides scheduled and Ad Hoc reporting, and monitors nightly batch file updates. The payroll allocations will be based on Utility Group Capitalization Factor.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Capitalization Factor	34.3%	23.7%	25.2%	16.8%	100%

Enterprise Management, Enterprise Development and Integration, Field Automation (Dept 723, 926, 964)
These teams support business and technical functions that are common to all brands. Provides support to the business through data requests and augments the system by developing programs and technical solutions to accommodate business and field needs as well as regulatory requirements. The payroll allocations will be based on Utility Group meter counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%

Enterprise GIS (Dept 951)
This department provides gas, electric and fiber pipeline and facilities mapping services for the Utility Group The payroll allocations will be based on Utility Group meter counts or time studies.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%

Environmental (Dept 889)
The Environmental Department provides environmental regulatory compliance guidance and assistance to MDU Utilities Group facilities and operations in accordance with the company environmental policy: The Company will operate efficiently to meet the needs of the present without compromising the ability of future generations to meet their own needs. Our environmental goals are:

- To minimize waste and maximize resources.
- To support environmental laws and regulations that are based on sound science and cost-effective technology; and
- To comply with or exceed all applicable environmental laws, regulations and permit requirements.

The payroll allocations will be based on time studies.

Safety & Technical Training (Dept 720, 901) ✓

The Safety and Technical Training department provides oversight for all things safety and technical training for the entire utility group. The payroll allocations will be based on Utility Group or Montana-Dakota employee counts or time studies, depending on the employee's job functions.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Employee Counts	27.2%	36.2%	21.3%	15.3%	100%
Montana-Dakota Utilities Employee Counts	42.9%	57.1%	-	-	100%

Business Development (Dept 918) ✓

The payroll allocations will be based on time studies.

Gas Supply (Dept 931, 933)✓

The payroll allocations will be based on two methodologies: Utility Group meter count and time studies. There are employees focused on Montana-Dakota Utilities functions, which will be allocated 100% to Montana-Dakota Utilities gas segment.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	-	40.5%	26.5%	33.0%	100%

Utility Group Controller (Dept 941)

The Controller Department provides various accounting services to the Utility Group: Fixed Assets Accounting, Revenue Accounting, Internal Controls Coordination, and Management. The payroll allocations are based on these methodologies: Utility Group customer count, Utility Group meter count, number of employees, Montana-Dakota customer factor, Utility Group corporate factor, Montana-Dakota corporate factor, and specific shared services methodologies.

- ***Utility Group customer count***
  - The following positions will be allocated based on Utility Group customer count based on job duties/functions:
    - Business Analyst I and II (Revenue Accounting)
- ***Utility Group meter count***
  - The following positions will be allocated based on Utility Group meter count based on job duties/functions:
    - Business Analyst II and Sr. (Customer Accounting)
- ***Number of employees***
  - The following positions will be allocated based on number of employees under their supervision:
    - Controller – Utility Group
    - Director, Finance
    - Manager, Revenue Administration
- ***Montana-Dakota customer factor***
  - The following positions will be allocated based on MDU customer factor
    - Financial Analyst I, II (Revenue Accounting)
    - Financial Specialist (Revenue Accounting)
    - Financial Technician (Revenue Accounting)
    - Manager, Revenue Accounting

- ***Utility Group corporate factor***
  - The following position will be allocated based on Utility Group corporate factor
    - Internal Controls Coordinator
- ***Montana-Dakota corporate factor***
  - The following positions will be allocated based on MDU corporate factor
    - Financial Analyst I, II, III, IV (Gen Acctg, Reporting & Planning)
    - Financial Systems Analyst (Gen Acctg)
    - Financial Technician (Gen Acctg)
    - Manager, Accounting & Finance
    - Manager, Financial Reporting & Planning
    - Manager, General Accounting

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Customer Counts	11.5%	24.1%	28.7%	35.7%	100%
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%
Number of Employees: Controller*	34.75%	24.0%	22.5%	18.75%	100%
Number of Employees: Director, Finance*	32.4%	22.4%	25.8%	19.4%	100%
Number of Employees: Manager, Revenue Administration**	19.1%	39.4%	22.0%	19.5%	100%
Montana-Dakota Customer Factor	32.6%	67.4%	-	-	100%
Utility Group Corporate Factor	34.4%	23.6%	25.1%	16.9%	100%
Montana-Dakota Corporate Factor	59.2%	40.8%	-	-	100%

* MDU electric/gas split is based on the MDU Corporate Factor.
** MDU electric/gas split is based on the MDU Customer Factor.

- ***Utility Group Fixed Assets Accounting methodology***
  - The following positions will be allocated based on time study:
    - Financial Analyst I, II, III, IV (Fixed Assets Accounting)
    - Supervisor, Fixed Assets Accounting
    - Manager, Fixed Assets Accounting

Costs for the Financial Analysts in the MDU Utility Group Fixed Asset Accounting group are invoiced based upon three separate methodologies based on the three major types of work performed in the department. The three major work types of work are:

1. Capital Expenditure Support (21.5% of workload)-Allocated to capital overhead (ES/GA) accounts based on 3-year average of capital expenditures.
2. Fixed Asset Life Cycle Support (63.5% of workload)-Allocated to capital overhead (ES/GA) accounts based on 3-year average of capital work orders weighted by a difficulty factor.
3. All Other Fixed Asset Accounting (15.0% of workload)-Allocated to expense (O&M) accounts based on estimate of time spent on non-project related tasks (Depreciation, ARO, Data Requests, etc.).

	MDUR*	MDU	WBIE**	KRC**	CSG**	CNG	IGC	Total
3-Year Average Capital Expenditures (Millions)		249.4				50.6	38.6	338.6
% of 3-Year Average Capital Expenditures		73.66%				14.94%	11.40%	100.00%
Capital Expenditure Support-21.5% Weight		15.84%				3.21%	2.45%	21.50%
3-Year Average Capital Work Orders		1,930				1,949	862	4,741
Difficulty Factor		68.29%				25.00%	25.00%	
Weighted % of 3-Year Average Capital WO's		65.22%				24.11%	10.67%	100.00%
Fixed Asset Life Cycle Support-63.5% Weight		41.41%				15.31%	6.78%	63.50%
% of Non-Project Related Task Time		62.64%				18.68%	18.68%	100.00%
All Other Fixed Asset Accounting-15% Weight		9.40%				2.80%	2.80%	15.00%
Totals		**66.65%**				**21.32%**	**12.03%**	**100.00%**
Total Allocated to ES/GA		57.25%				18.52%	9.23%	85.00%
Total Allocated to O&M		9.40%				2.80%	2.80%	15.00%

* Time devoted to CHCC companies deemed immaterial and is included in MDU amounts.
** No service provided to WBIE, CSG or CSG

Costs for the Manager of the Utility Group Fixed Asset Accounting group are invoiced based upon the company workload split of the "Other Fixed Asset Accounting" time spent by the Lead Financial Analyst in charge of depreciation, ARO's, data requests, etc. No portion of these costs is allocated to capital overhead (ES/GA) as they are deemed to be non-direct construction support costs.

	MDUR*	MDU	WBIE**	KRC**	CSG**	CNG	IGC	Total
Other Fixed Asset Acct. Workload of Lead Non-Project Support F/A		50.00%				10.00%	10.00%	70.00%
% Allocation of UGFA Manager Costs to O&M		71.42%				14.29%	14.29%	100.00%
Totals		**71.42%**				**14.29%**	**14.29%**	**100.00%**

* Time devoted to CHCC companies deemed immaterial and is included in MDU amounts.
** No service provided to WBIE, CSG or CSG

- ***Utility Group Payment Processing methodology***
    - Payment Processer (Revenue Accounting)
    - Payment Processer, Lead (Revenue Accounting)

Payment Processing has been allocated by utility brand based on the number of customer payments posted to utility accounts in the 12 month period ending June 30, 2018.

	CNG	IGC	MDU/GPNG	Total
# of Payments Processed	957,174	1,057,909	1,876,189	3,891,272
% of Payments Processed by Brand	24.6%	27.2%	48.2%	100%

Exhibit VI- Utility Operations Allocation Factors

Cascade Natural Gas Corporation
State Allocation Formulas
2018

	Washington	Oregon	Total
Customers	74.30%	25.70%	100.00%
Employees	73.72%	26.28%	100.00%
Gross Plant	77.49%	22.51%	100.00%
3-Factor Formula	75.17%	24.83%	100.00%
Rate Base Ratio	75.54%	24.46%	100.00%

Cascade Natural Gas Corporation
Average No. of Employees
2018

Source: Customers Per Employee report	Mo-Yr	Washington District Employees (1)	Oregon District Employees (1)	
	Dec-17	172	62	
	Jan-18	173	62	
	Feb-18	173	60	
	Mar-18	173	60	
	Apr-18	172	60	
	May-18	172	59	
	Jun-18	179	62	
	Jul-18	179	63	
	Aug-18	177	63	
	Sep-18	169	63	
	Oct-18	170	63	
	Nov-18	176	65	
	Dec-18	174	65	
		2,259	807	
Average of Monthly Averages		174	62	236
	Percentage	73.72%	26.28%	100.00%

(1) Excludes Interstate employees

Cascade Natural Gas Corporation
Gross Plant Percentage
2018

	Washington Incl. CCNC	Oregon Incl. CCNC	Total
Avg. of Mo. Avg.s	780,275,999	226,716,210	1,006,992,209
Percentage	77.49%	22.51%	100.00%

Cost Allocation Manual

Cascade Natural Gas Corporation
Average Number of Customers
2018

	Average No. of Customers	Percentage
Washington	214,996	74.30%
Oregon	74,377	25.70%
Total	289,373	100.00%

Cost Allocation Manual

Cascade Natural Gas Corporation
Rate Base Ratio
2018

The following percentages are used for allocating interest on debt:

	2018 Average Rate Base	Plant Formula
Washington	302,980,258	75.54%
Oregon	98,079,245	24.46%
	401,059,503	100.00%

Request No. 204

Date prepared: June 22, 2020

Preparer: Linda Offerdahl

Contact: Chris Mickelson

Telephone: (509)-734-4549

204. Regarding the Shevlin Park Project,
   a. Please split the project costs in the table on CNGC/200, Darras/20 by year.
      i. Please provide a reconciliation to Exhibit 305 if the 2020 figures are different.
   b. Regarding the 4000' of main discussed on CNGC/200, Darras/20,
      i. Please provide a narrative explanation of what being "placed on nitrogen" entails.
      ii. Please identify any dockets or Commission orders where this section of main was discussed.
      iii. Please provide a narrative explanation of any period of time that this line was presently used providing utility service to customers since 2012.
      iv. Please provide the total installed cost of the main.
      v. Please provide a narrative discussion of the anticipated expansion needs in 2012 and how changes in economic conditions have affected when this section of main is placed into use.
   c. Please provide a narrative explanation of the additional infrastructure investment that will be needed to serve the "1,000 homes in 2-4 years" cited in Figure 3.
   d. Please provide a narrative explanation of the incremental costs to the Company of bypass operations discussed on CNGC/200, Darras/18 and a list of bypass events that occurred in the last 3 years.
   e. Please quantify the anticipated "efficiencies and cost savings" discussed on CNGC/200, Darras/18.
   f. Please provide a narrative explanation of how the Company participated in the planning and development agreements cited in the footnote on page CNGC/200, Darras/15 including why the plans were not known in time for the 2018 IRP as noted on CNGC/200, Darras/19.

Response:

The Shevlin Park Project has been postponed to 2021 due to COVID-19 impacts. The Company will remove this project from the UG390 request in a rebuttal filing.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 390

In the Matter of	)
	)
Cascade Natural Gas Corporation	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/103

July 30, 2020

Guidelines for Cost Allocations and Affiliate Transactions:

The following Guidelines for Cost Allocations and Affiliate Transactions (Guidelines) are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates. The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. They are intended to provide a framework for regulated entities and regulatory authorities in the development of their own policies and procedures for cost allocations and affiliated transactions. Variation in regulatory environment may justify different cost allocation methods than those embodied in the Guidelines.

The Guidelines acknowledge and reference the use of several different practices and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight. The implementation and compliance with these cost allocations and affiliate transaction guidelines, by regulated utilities under the authority of jurisdictional regulatory commissions, is subject to Federal and state law. Each state or Federal regulatory commission may have unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing standards. For example, The Public Utility Holding Company Act of 1935 requires registered holding company systems to price "at cost" the sale of goods and services and the undertaking of construction contracts between affiliate companies.

The Guidelines were developed by the NARUC Staff Subcommittee on Accounts in compliance with the Resolution passed on March 3, 1998 entitled "Resolution Regarding Cost Allocation for the Energy Industry" which directed the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations." In addition, input was requested from other industry parties. Various levels of input were obtained in the development of the Guidelines from the Edison Electric Institute, American Gas Association, Securities and Exchange Commission, the Federal Energy Regulatory Commission, Rural Utilities Service and the National Rural Electric Cooperatives Association as well as staff of various state public utility commissions.

In some instances, non-structural safeguards as contained in these guidelines may not be sufficient to prevent market power problems in strategic markets such as the generation market. Problems arise when a firm has the ability to raise prices above market for a sustained period and/or impede output of a product or service. Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates. Consideration should be given to any "unique" advantages an incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions.

A. DEFINITIONS

1. Affiliates - companies that are related to each other due to common ownership or control.

2. Attestation Engagement - one in which a certified public accountant who is in the practice of public accounting is contracted to issue a written communication that expresses a conclusion about the reliability of a written assertion that is the responsibility of another party.

3. Cost Allocation Manual (CAM) - an indexed compilation and documentation of a company's cost allocation policies and related procedures.

4. Cost Allocations - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

5. Common Costs - costs associated with services or products that are of joint benefit between regulated and non-regulated business units.

6. Cost Driver - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. Direct Costs - costs which can be specifically identified with a particular service or product.

8. Fully Allocated costs - the sum of the direct costs plus an appropriate share of indirect costs.

9. Incremental pricing - pricing services or products on a basis of only the additional costs added by their operations while one or more pre-existing services or products support the fixed costs.

10. Indirect Costs - costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.

11. Non-regulated - that which is not subject to regulation by regulatory authorities.

12. Prevailing Market Pricing - a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

13. Regulated - that which is subject to regulation by regulatory authorities.

14. Subsidization - the recovery of costs from one class of customers or business unit that are attributable to another.

B. COST ALLOCATION PRINCIPLES

The following allocation principles should be used whenever products or services are provided between a regulated utility and its non-regulated affiliate or division.

1. To the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided.

2. The general method for charging indirect costs should be on a fully allocated cost basis. Under appropriate circumstances, regulatory authorities may consider incremental cost, prevailing market pricing or other methods for allocating costs and pricing transactions among affiliates.

3. To the extent possible, all direct and allocated costs between regulated and non-regulated services and products should be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. Documentation should be made available to the appropriate regulatory authority upon request regarding transactions between the regulated utility and its affiliates.

4. The allocation methods should apply to the regulated entity's affiliates in order to prevent

subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa.

5. All costs should be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

6. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.

7. The indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.

C. COST ALLOCATION MANUAL (NOT TARIFFED)

Each entity that provides both regulated and non-regulated services or products should maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. The determination of what, if any, information should be held confidential should be based on the statutes and rules of the regulatory agency that requires the information. Any entity required to provide notification of a CAM(s) should make arrangements as necessary and appropriate to ensure competitively sensitive information derived therefrom be kept confidential by the regulator. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company, depicting all affiliates, and regulated entities.

2. A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.

3. A description of all assets, services and products provided by the regulated entity to non-affiliates.

4. A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

D. AFFILIATE TRANSACTIONS (NOT TARIFFED)

The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization. However, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged.

The objective of the affiliate transactions' guidelines is to lessen the possibility of subsidization in order to protect monopoly ratepayers and to help establish and preserve competition in the electric generation and the electric and gas supply markets. It provides ample flexibility to accommodate exceptions where the outcome is in the best interest of the utility, its ratepayers and competition. As with any transactions, the burden of proof for any exception from the general rule rests with the proponent of the exception.

1. Generally, the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation.

E. AUDIT REQUIREMENTS

1. An audit trail should exist with respect to all transactions between the regulated entity and its affiliates that relate to regulated services and products. The regulator should have complete access to all affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with the guidelines. Regulators should have complete access to affiliate records, consistent with state statutes, to ensure that the regulator has access to all relevant information necessary to evaluate whether subsidization exists. The auditors, not the audited utilities, should determine what information is relevant for a particular audit objective. Limitations on access would compromise the audit process and impair audit independence.

2. Each regulated entity's cost allocation documentation should be made available to the company's internal auditors for periodic review of the allocation policy and process and to any jurisdictional regulatory authority when appropriate and upon request.

3. Any jurisdictional regulatory authority may request an independent attestation engagement of the CAM. The cost of any independent attestation engagement associated with the CAM, should be shared between regulated and non-regulated operations consistent with the allocation of similar common costs.

4. Any audit of the CAM should not otherwise limit or restrict the authority of state regulatory authorities to have access to the books and records of and audit the operations of jurisdictional utilities.

5. Any entity required to provide access to its books and records should make arrangements as necessary and appropriate to ensure that competitively sensitive information derived therefrom be kept confidential by the regulator.

F. REPORTING REQUIREMENTS

1. The regulated entity should report annually the dollar amount of non-tariffed transactions

associated with the provision of each service or product and the use or sale of each asset for the following:

a. Those provided to each non-regulated affiliate.

b. Those received from each non-regulated affiliate.

c. Those provided to non-affiliated entities.

2. Any additional information needed to assure compliance with these Guidelines, such as cost of service data necessary to evaluate subsidization issues, should be provided.