BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

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

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS

REDACTED VERSION

September 27, 2018

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins. My business address is 1750 SW Harbor Way, Ste 450, Portland, Oregon 97201.

Q. PLEASE STATE YOUR OCCUPATION AND IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent consultant representing utility customers before state regulatory commissions in the Pacific Northwest. I am appearing on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users served by electric and gas utilities located throughout the West, including customers that receive gas sales and transportation services from Cascade Natural Gas Corporation ("Cascade" or "Company"), a wholly owned subsidiary of MDU Resources Group Inc. ("MDU Resources").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. A summary of my education and work experience can be found at Exhibit AWEC/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my review of Cascade's proposed $2,310,808 margin revenue increase, an approximate 6.6% increase to margin rates. My analysis demonstrates that not only are Cascade's rates sufficient, they should be reduced by $3,592,731 or 10.28% of margin rates. I also discuss deficiencies in Cascade's class cost of service study and its proposal for a safety tracker.

Q. WHAT WAS THE SCOPE OF YOUR REVIEW?

A. I reviewed the Direct Testimony of Cascade witnesses Michael Parvinen, Maryalice Peters, and Ronald Amen. I conducted two rounds of discovery and have reviewed the Company's responses to those discovery requests, as well as responses to requests from other parties. Finally, I prepared supplemental revenue requirement and cost of service analytics, including analysis of the impacts of the recent tax reform, which I have attached to this testimony.

Q. WHAT IS YOUR RECOMMENDATION ON REVENUE REQUIREMENT?

A. Based upon the revenue requirement analysis in Exhibit AWEC/102, I recommend the Commission reduce Cascade's revenue requirement by $3,592,731, a 10.3% reduction to margin rates. The first page of Exhibit AWEC/102 contains a cross-walk between my revenue requirement proposal and that of Cascade, and as noted from the summary of that analysis in Table 1 below, I have made several adjustments to Cascade's revenue requirement calculation.

TABLE 1
AWEC Revenue Requirement Adjustments
Revenue Deficiency / (Sufficiency), (In Thousands)

Line	Issue			
1		**Cascade Initial Filing**		**2,311**
		Misc. Adjustments		
2		Cost of Debt	(86)	
3		Correct Conversion Factor	(6)	
4		Subtotal		(92)
		Corporate Allocation		
5	A1	Corporate Overhead Rate	(655)	
6	A2	Utility Group Allocations	(13)	
7	A3	Incentives	(206)	
8	A4	Dues and Subscriptions	(9)	
9	A5	Legal Expenses	(59)	
10	A6	Taxes Other Than Income Taxes	(31)	
11		Subtotal		(974)
		Tax Adjustments		
12	A7	Effective State Tax Rate	(166)	
13	A8	Excess Deferred Federal Income Taxes ("EDFIT")	(733)	
14	A9	Interim Period Deferral	(1,296)	
15		Subtotal		(2,195)
		Plant Adjustments		
16	A10	Remove Growth Projects	(1,400)	
17	A11	Madras Project	(1,169)	
18	A12	Retirements	(168)	
19		Interest Sync.	93	
20		Subtotal		(2,643)
21		**AWEC Recommended**		**(3,593)**
22		Margin%		-10.28%

Q. WHAT IS YOUR RECOMMENDATION ON COST OF SERVICE?

A. I recommend that the rate reduction be applied in this matter on an equal percent of margin basis. Cascade's rate spread proposal arbitrarily increases Schedule 163 transportation customer rates by 19.87%. Cascade's study is flawed, however, because it assumes a Schedule 902-2 special contract customer will migrate to Schedule 163, but then inexplicably does not include the special contract customer revenues when calculating the parity ratios for Schedule 163. If the Schedule 902-2 revenues are included in Schedule 163, the study shows that the Schedule 163 revenue-to-cost ratio is 120% and that, in no case, should a rate increase be applied to Schedule 163 customer margins.

Q. WHAT IS YOUR RECOMMENDATION ON THE SAFETY TRACKER PROPOSAL?

A. While AWEC appreciates Cascade's desire to continue to provide safe and reliable service, the proposed mechanism is unnecessary to achieve those goals. The proposal is similar to one filed by Intermountain Gas Company ("Intermountain") in Idaho, an affiliate of Cascade. The Idaho Commission rejected the mechanism because it was a single-issue ratemaking proposal, and such costs should be recovered through traditional ratemaking. This Commission should follow that approach. Here, Cascade has not identified anything with the traditional ratemaking methods that would prohibit recovery of the expenditures associated with its capital investment program. To address Cascade's safety program, a depreciation study should first be performed. Once the depreciation study is in place, a general rate case is the proper place for Cascade to address the issues associated with the accelerated rate of plant retirements and replacements.

II. CORPORATE COST ALLOCATION

Q. WHY IS CORPORATE COST ALLOCATION SUCH A SIGNIFICANT ISSUE FOR CASCADE?

A. As utilities become increasingly consolidated, corporate cost allocation becomes an increasingly important issue. Not to be confused with class cost of service allocations, "cost allocation" in this context refers to the allocation of items of expense, revenue, and rate base by and between the legal entities within the consolidated group of Cascade's parent, MDU Resources. This section of my testimony also addresses inter-jurisdictional cost allocation of Cascade's operations between Washington and Oregon jurisdictions, since inter-jurisdictional cost allocation operates in tandem with corporate cost allocation for Cascade.

The importance of corporate cost allocation is due to the fact that many mergers in Oregon, including the one in which Cascade was acquired by MDU Resources, have been justified on the basis of forecasted net benefits to ratepayers that will be produced. Notwithstanding, when the merger is actually executed, those benefits, sometimes referred to as synergies, never materialize for ratepayers. Rather than producing synergies, it has been my experience that a utility operating company often becomes a dumping ground for costs within the consolidated group, and when considering the synergy forecast in a merger docket, utilities often do not consider the offsetting impact of aggressive corporate cost allocation policies that actually serve to increase the costs allocated to Oregon's ratepayers. Simply put, ratepayers are not interested in subsidizing MDU Resources' many other corporate enterprises and there should be no expectation for them to do so.

Q. PLEASE PROVIDE AN OVERVIEW OF THE CORPORATE ORGANIZATIONAL STRUCTURE OF CASCADE'S PARENT, MDU RESOURCES.

A. In response to AWEC Data Request 13, Cascade provided MDU Resources' corporate organizational diagram, including all legal entities owned or controlled by MDU Resources as of August 17, 2018. That response shows that MDU Resources' operations span a wide range of construction, financial, utility, and energy related business enterprises. Knife River, for example, is a subsidiary of MDU Resources, and is a large, well known supplier of construction material, such as asphalt and concrete.

Q. DOES MDU RESOURCES HAVE A WRITTEN POLICY THAT GOVERNS COST ALLOCATION BETWEEN ITS SUBSIDIARIES?

A. No. Cascade did not provide a cost allocation manual that governs all intra-company cost allocations within the MDU Resources consolidated group. Cascade did, however, produce a cost allocation manual that it uses for regulatory purposes to describe the costs Cascade allocates to its regulatory operations. The most recent cost allocation manual was provided as an attachment to Cascade's response to Staff Data Request 164.

Q. PLEASE DESCRIBE THE COST ALLOCATION PROCEDURE CASCADE USES.

A. When developing its regulated results, Cascade's books include innumerous cross-charges. A cross-charge represents an intercompany entry that is not actually realized or paid by the utility itself. Rather, the amount is paid by some another entity within the consolidated group and reassigned to the utility corporation for cost accounting purposes only.

For Cascade, corporate cost allocation is complicated and consists of at least three layers of cross-charges and allocations. First, cross-charges for overhead-related costs are assigned from the MDU Resources parent directly to the Cascade entity. Second, cross charges for service related costs are allocated between Cascade, Intermountain, and Montana-Dakota Utilities. Finally, costs are allocated within the Cascade entity between the Washington and Oregon jurisdictions.

Q. ARE CROSS-CHARGES REVIEWED BY FINANCIAL AUDITORS?

A. No. In the process of consolidation, intercompany entries are eliminated, and, therefore, cross-charges such as those included in Cascade's revenue requirement are typically not reviewed by financial auditors when opining on consolidated financial statements.

Q. WHAT IS YOUR UNDERSTANDING OF THE STANDARD FOR INCLUDING ALLOCATED COSTS, SUCH AS THESE, IN REVENUE REQUIREMENT?

A. Since the costs in question are not verifiable expenses of the Cascade entity and are actually being incurred by another entity, the presumption should be that no such costs should be allocated, in the absence of a clear and identifiable benefit to Oregon customers consistent with the known and measurable and used and useful analysis used in Oregon. If a cost is incurred at the utility itself, the presumption is flipped and there is a presumption that the cost was incurred in connection with utility operations.

As I discuss below, the net effect of the multiple layers of corporate cost allocation results in an overstatement of the costs that are appropriately paid by Oregon customers. I look first at the inappropriate way that corporate overhead is being allocated.

a. <u>Corporate Overhead Allocator</u>

Q. HOW DOES CASCADE ALLOCATE CORPORATE OVERHEAD FROM MDU RESOURCES?

A. Cascade's revenue includes allocations of a large number of corporate overhead costs—e.g. accounting, investor relations, corporate legal expenses—from MDU Resources. With the exception of shared services, corporate costs are assigned on the basis of a single corporate overhead allocator percentage. Cascade also applies a secondary overhead allocator for overhead costs incurred in the utilities group, consisting of Montana Dakotas, Cascade and

Intermountain, and then a third allocator for overhead incurred amongst Cascade and Intermountain.

Q. HOW IS THE CORPORATE OVERHEAD ALLOCATOR CALCULATED?

A. Cascade calculates the corporate overhead allocator solely on the basis of "capitalization," which Cascade defines as book stockholders equity, plus total debt. Effectively, this equates to the net book value of the respective business entities.

Q. DOES THE COST ALLOCATION MANUAL PROVIDE AN ILLUSTRATION OF THE CALCULATION?

A. Exhibit I of the Cost Allocation Manual provides an illustration of how the calculation is performed. Further, Cascade's response to AWEC data request 15 provides support for the values for the overhead allocator expenses it proposes to use in the test period, although that response contained only hard-coded numbers and did not include the underlying calculations supporting the overhead allocator. In response to a follow up request in AWEC data request 41, Cascade was still unable to provide responsive workpapers used to calculate the overhead allocator using the methodology outlined in Exhibit I of the Cost Allocation Manual. Cascade's response to AWEC data request 41 included only PDF documents with no additional detail necessary to support its overhead allocator percentages.

Q. IS THAT REASONABLE TO RELY ON "CAPITALIZATION" OR NET BOOK VALUE AS THE SOLE BASIS FOR ALLOCATING OVERHEAD COSTS?

A. No. Cascade's capitalization metric is basically the net book value of the respective entities, and book values have little to do with determining which business enterprises might be responsible for common overhead costs. This sort of approach inherently penalizes an asset-heavy utility relative to, for example, a construction services company, which may have fewer fixed assets and relatively low book values. In addition, utilities are not allowed to set rates based on book values. Book values include numerous adjustments, such as acquisition premiums, that utilities are prohibited from recovering from Oregon ratepayers through rate base. Thus, if a capitalization approach is to be used, it should be based on the utility's rate base, not its net book value.

Q. WHAT FACTORS SHOULD BE CONSIDERED WHEN ALLOCATING OVERHEAD COSTS?

A. Labor, through the use of metrics such as employee count and total wages, is usually treated as a key driver in determining overhead cost responsibility.[1] Other methods such as looking at the relative operations and maintenance expenses of the business lines have been used as well. Revenues are also commonly considered when allocating overhead costs. From a ratemaking perspective, it is recognized that there is no single right answer for questions related to cost allocation. Accordingly, it is common to blend and weight a number of factors when allocating common costs through the use of 2-, 3-, or 4-factor allocation factors, which is what I recommend below.

Q. SHOULD THE HOLDING COMPANY ITSELF BE RESPONSIBLE FOR A PORTION OF OVERHEAD COSTS?

A. Yes. Operating a holding company is, in itself, a business and ratepayers should not be responsible for the general costs of operating a holding company. Under Cascade's approach, 100% of the overhead costs are allocated to the operating businesses and no overhead costs are allocated to the holding company operations. Just as some overhead cost may be reasonably

---

1 See e.g. National Association of Regulatory Utility Commissioners Electric Cost Utility Cost Allocation Manual at 106 (Jan 1992).

allocated from MDU Resources to Cascade, a portion of the overhead costs must be assumed to benefit the holding company itself, and thus, not assigned to any subsidiary. Activities, such as seeking out new mergers and acquisitions or considering strategic reorganizations, are examples of activities that are performed not for the benefit of any particular subsidiary, but for the holding company itself.

Notwithstanding, the holding company typically possesses few assets, and no revenues to speak of. Accordingly, allocation methods that rely on plant or revenues do not allocate any cost to the holding company itself, which is unfair to ratepayers. To account for this feature when viewing the plant or revenue-based allocators, it is appropriate to use a judgmental weighting to remove a reasonable amount of costs which may be attributable to holding company activities. As discussed below, I believe that applying a judgmental 25% allocation of overhead costs to the holding company is an appropriate assumption.

Q. HOW DOES THE "CAPITALIZATION" FACTOR COMPARE OTHER POTENTIAL OVERHEAD ALLOCATION FACTORS?

A. In Exhibit AWEC/105, I performed an analysis comparing a number of potential corporate overhead cost allocators, based on labor, sales, and plant values. The analysis, which has been summarized in Table 2 below, shows using book capitalization as the allocator for Cascade's asset-heavy utility business lines is by far the most punitive to Oregon ratepayers. Table 2 also shows my recommendation.

TABLE 2
Comparison of Potential Overhead Cost Allocators

	Knife River	WBI Resources	Constr. Services	Dakota Util.	Intermtn Natural Gas	Cascade (System)	MDU Resources	Total
A1.Book Capital (as proposed by Cascade)	22.4%	13.0%	8.8%	33.6%	9.6%	13.9%	0.0%	101.2%
A2 . Capital (using rate base in place of book balue)	16.9%	11.1%	6.1%	23.7%	10.4%	6.8%	25.0%	100.0%
B1. Wages	47.9%	4.5%	2.2%	13.1%	2.9%	4.4%	25.0%	100.0%
B2. Employee Count (2017 Average)	28.4%	2.2%	33.7%	6.9%	1.6%	2.3%	25.0%	100.0%
C. Gross Revenues	30.3%	2.0%	22.8%	10.4%	4.6%	4.8%	25.0%	100.0%
Proposed 4-Factor	30.8%	5.0%	16.2%	13.5%	4.9%	4.6%	25.0%	100.0%

As noted in Exhibit AWEC/105, while Cascade may make up approximately 13.9% of MDU Resources' capitalization, in the way that Cascade defines that term, it constitutes only than 6.5% of MDU Resources revenues. Further, only 3.0% of MDU Resources employees work at Cascade and Cascade accounts for only 5.7% of employee wages.

Q. WHAT ALLOCATOR DO YOU RECOMMEND?

A. I recommend using a 4-factor formula to determine the allocation, with a double weighting applied to labor. Under my recommended approach, wages, employee count, revenue, and net plant would be the factors. Double weighting labor, through the use of both a wage and employee count factor, is appropriate since employees are a key driver of overhead costs. The calculation of these factors can be seen in Table 2, above.

Q. HOW HAVE YOU ACCOUNTED FOR HOLDING COMPANY ACTIVITIES IN THE FACTORS ABOVE?

A. In my analysis, I allocated 25% of all corporate overhead costs first to the holding company when calculating allocators based on plant, labor and revenues. This approach recognizes that the majority of overhead costs benefit the subsidiaries, while one quarter benefits the holding company itself.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. To estimate the impact, I relied on Cascade's revised response to Staff data request 57. I took all of the accounting entries identified as a cross charge in the Administrative and General line item of the results of operations, excluding the allocation of service-related costs. I estimate the impact of adopting the proposed allocator in Table 2 by dividing the allocated cost by the old allocation factor and multiplying by the new factor. Based on this, I estimate the impact of using the overhead allocator identified in Table 2 to be a $636,377 reduction to Oregon-allocated net operating income, a $655,147 reduction to revenue requirement.

b. <u>Allocation of Utility Group Overhead</u>

Q. WHAT IS THE ISSUE RELATED TO CASCADE'S USE OF A CUSTOMER COUNT ALLOCATOR?

A. The use of a customer count as an allocation factor is relevant when Cascade allocates common costs amongst the three utilities: Cascade, Intermountain and Montana Dakota Utilities. Montana-Dakota Utilities is the most complicated utility of the three, since it provides both gas and electric services and does so in four different jurisdictions: Montana, North Dakota, South Dakota and Wyoming.

In response to AWEC data request 42, part c, Cascade noted that, to account for the fact that Montana Dakota Utilities customers are both gas and electric customers, it multiplied the customer count for the utility by 1.25%. Cascade provided no justification or additional support for the 1.25% value.

Q. DO YOU AGREE WITH CASCADE'S APPROACH?

A. No. I recommend treating a customer who is both a gas and electric customer of Montana Dakota Utilities as two customers. The gas and electric utilities of Montana Dakota Utilities are two separate business lines, and thus, customers that receive both electric services and gas services should be counted as two separate customers. That is fair, particularly in light of the fact that Montana-Dakota Utilities has much more complicated utility operations than Cascade and Intermountain, since it operates in four different jurisdictions.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. I requested the workpapers to perform this calculation in AWEC data request 17. Cascade responded with an excel file containing a list of customer service employees and allocation percentages for those employees. The list did not appear to be the comprehensive list of shared employee service costs that are being allocated between the utilities. When I followed-up in AWEC data request 42, no further data was provided. Accordingly, to estimate the impact of this adjustment, I took the accounting data provided in Cascade's supplemental response to Staff Data Request 57 and assumed that approximately 1/3rd of the cost of service cross-charges were being allocated on the basis of customer count. Based on those assumptions, the estimated impact was relatively small, an increase of only approximately $13,000 to Oregon allocated net income.

c. Allocated Incentives

Q. WHAT IS YOUR CONCERN WITH RESPECT TO THE ALLOCATION OF INCENTIVES?

A. First, Cascade's analysis only removed executive incentives, and ignored the remaining employee incentives provided to non-executives, which is inconsistent with past practice in Oregon. Further, Cascade's analysis includes a significant portion of incentives which have been allocated from other business lines.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that Cascade remove the full 50% of incentives, consistent with past practice in Oregon. Further, I recommend that Cascade not be permitted to recover the cost of incentives paid to employees of entities other than Cascade.

Q. WHY SHOULD INCENTIVES OF OTHER ENTITIES BE REMOVED?

A. If an employee is employed by another entity, the employee has an obligation to act in the interest of its employer, not Cascade or Cascade's customers. Those employees are not incentivized in a way that provides benefits to Cascade's Oregon customers, and it would be necessary for Cascade to provide clear and convincing evidence of the benefit if those amounts are to be included. For example, Cascade includes $104,286 of incentive costs allocated from general employees of Montana Dakota Utilities (the sister gas and electric utility, not the holding company), and the incentives provided to those employees have no bearing on the quality or cost of service to Oregon ratepayers.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Removing the allocated incentives and removing 50% of the remainder, consistent with past Commission practice, results in an approximate $509,364 reduction to Oregon-allocated operating expenses. Relative to Cascade's adjustment of $309,033, my recommendation results in an operating expense adjustment of $200,331 and a corresponding revenue requirement reduction of $206,240.

d. <u>Allocation of Dues and Subscriptions</u>

Q. WHERE DID CASCADE PROVIDE DETAIL UNDERLYING ADVERTISING, AND DUES AND SUBSCRIPTIONS?

A. In response to Staff data request 90, Cascade provided its calculation of the dues and subscriptions it proposes in revenue requirement. I have a number of concerns with those workpapers.

Q. WHAT ARE YOUR CONCERNS WITH CASCADE'S CALCULATIONS?

A. First, Cascade includes allocated costs from MDU and other entities, which have no bearing on Oregon rates. Cascade's response to AWEC Data Requests 46 and 47, for example, highlights Montana Dakota Utilities' sponsorship of a random professional bull rider and sponsorship of an obscure minor league baseball team.

Second, when performing jurisdictional allocation, Cascade undertakes a process to situs assign certain categories for these costs to Oregon, but does not undertake a similar process of directly assigning costs to Washington, before allocating costs between the two states.

Q. WHAT DO YOU RECOMMEND?

A. In preparing my revenue requirement, I removed all cross-charges from the account in question because, based on my review of the allocation manual, Cascade has no cost allocation policy in place with respect to these cost categories. Further, several specific expenditures that are being allocated to Oregon customers appear have no bearing on, and provide no benefit to, Oregon customers. In addition, I recommend situs assigning costs that are clearly attributable to Washington operations, prior to allocating to Oregon.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. In my workpapers, I detail the particular lines that I have removed from Cascade's calculation. As demonstrated in my workpapers, this adjustment results in a $9,131 reduction to operating expenses, and a corresponding $9,416 reduction to revenue requirement.

e. Allocation of Taxes Other Than Income Taxes

Q. WHAT AMOUNT OF CROSS CHARGES DOES CASCADE INCLUDE FOR TAXES OTHER THAN INCOME TAXES?

A. In Cascade's revised response to OPUC Data Request 57, I have identified approximately $29,899 of costs allocated for taxes other than income taxes.

Q. ARE THOSE AMOUNTS APPROPRIATELY ASSIGNED TO OREGON RATEPAYERS?

A. No. There is no provision in the cost allocation manual for allocating taxes other than income taxes to Cascade. Accordingly, it is not appropriate to include those costs in revenue requirement. Removing them results in an $30,781 reduction to revenue requirement.

III. INCOME TAX ISSUES

Q. WHAT AMOUNT OF FEDERAL TAXES DID CASCADE PAY IN 2015 AND 2016?

A. Zero. In 2015 and 2016, neither Cascade nor its parent MDU Resources (nor any other entity in the consolidated group, for that matter) paid a single dollar of income taxes to the US Treasury. This is evident from MDU Resource's consolidated Form 1120, its federal income tax returns for those periods, which have been attached to my testimony as Exhibit AWEC/106.

Q. WHAT AMOUNT OF OREGON STATE TAXES DID CASCADE PAY IN 2015 AND 2016

A. [redacted] This is evident from MDU Resource's Oregon income tax returns which have been attached to my testimony as Confidential Exhibit AWEC/107.

Q. WHAT AMOUNT IS CASCADE PROPOSING TO RECOVER TAXES FROM RATEPAYERS?

A. Cascade proposes to collect approximately $1,745,183 in revenue requirement to cover the cost of federal and state income taxes.

Q. IS THAT FAIR?

A. Absolutely not. It is problematic from many perspectives. Ratepayers pay rates with the expectation that a certain amount of the revenues will be paid as taxes for the benefit of the general public. For example, if nothing is being remitted to the federal government, then ratepayers are paying something but getting nothing in return. Further, the regulatory policy with respect to taxes has been evolving quickly. The US Court of Appeals, DC Circuit, for instance recently decided the case of *United Airlines vs the Federal Energy Regulatory Commission*,[2] which resulted in removal of the tax allowance altogether for those pipelines not subject to entity level tax. The same logic in that case also applies to a utility that files taxes as a part of a consolidated group, such as Cascade.

Q. HAS CASCADE CONSIDERED ALL OF THE IMPACTS RELATED TO TAX REFORM?

A. No. In addition to dealing with the fact that Cascade is not paying any federal taxes and [redacted] state taxes, it is also necessary to consider the general revenue requirement impacts

---

[2] *United Airlines, Inc v. FERC*, 827 F.3rd 122 (D.C. Cir. 2016)

of the Tax Cut and Jobs Act ("TCJA"), HR1 of the 115th Congress, which reduced corporate income tax rates from 35% to 21%. Cascade has considered some of those impacts, but has ignored others. This is similar to the approach Cascade took in Washington in its recent rate filing. In its Final Order, the Washington Commission ordered Cascade to return to ratepayers all of the benefits of the TCJA.[3]

AWEC has concerns over the calculation of Excess Deferred Federal Income Taxes ("EDFIT") based on Cascade's purported use of the Average Rate Assumption Methodology ("ARAM"), and recommends that the Alternative Method be applied, in conjunction with returning the unprotected balances over a shorter, two-year period of time. In addition, Cascade has not proposed to return the Interim Period tax savings that accrue over the 15-month period from January 1, 2018 through April 1, 2019. Finally, it is also necessary to consider the effects of a multi-state apportionment issue that I have identified below, when determining the tax allowance in Cascade's revenue requirement. I discuss the state tax issues below first, followed by a discussion of tax reform.

a. <u>Oregon State Taxes</u>

Q. WHAT EFFECTIVE STATE TAX RATE DOES CASCADE USE TO CALCULATE REVENUE REQUIREMENT?

A. Cascade uses an effective state tax rate of 7.4% to calculate the effects of state taxes on revenue requirement.

[3] W.U.T.C. vs Cascade Natural Gas Corporation, Wa.UTC Docket No. UE 170929, Order 06 (Jul. 20, 2018).

Q. IS THAT CASCADE'S ACTUAL EFFECTIVE STATE TAX RATE?

A, No. Based on Cascade's response to AWEC Data Request 5, the effective state tax rate that Cascade uses in preparing its audited financial statements was just 1.8049%, before considering the effects of the federal benefit associated with the state tax deduction. Since Cascade is included in a consolidated tax return, the net income generated by the utility in Oregon gets spread out amongst all of the taxing jurisdictions where MDU Resources has situs. The tax generated from income within the Cascade natural gas entity is allocated through an apportionment process to all of the states where MDU Resources operates. As a result of the apportionment process, the actual state taxes that MDU pays on income generated from Cascade ends up being much lower than the Oregon rate of 7.4%.

Q. WHY IS CASCADE PAYING [redacted] STATE TAXES?

A. Cascade [redacted] files using an apportionment method, which allows Cascade to use the losses generated by other operating divisions to offset its Oregon state taxes, irrespective of whether the other operating division is located in Oregon. The outcome is that large tax losses from other states may be allocated to Oregon, which ultimately results in [redacted] paid in Oregon. Thus, apportionment is at the heart of the issue [redacted] and at a minimum, the state taxes in revenue requirement should be based on the actual effective state tax rate Cascade uses for financial accounting purposes.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Adopting the lower state effective tax rate results in a $162,530 reduction to revenue requirement.

b. Excess Tax Reserves

Q. WHAT ARE EXCESS DEFERRED FEDERAL INCOME TAXES?

A. The TCJA codifies several normalization provisions surrounding the treatment of EDFIT, which prescribes specific treatment of the balance sheet impacts of the tax law change for public utilities. Similar provisions were put into place when the Tax Reform Act of 1986 was enacted.[4/]

Effectively, EDFIT represent a financial gain to the utility, and absent the TCJA normalization provisions surrounding EDFIT, a utility might have claimed that it was entitled to retain those benefits. Or, perhaps ratepayers might have claimed that they should receive those gains through a single lump-sum payment. The TCJA, however, simplifies the ratemaking treatment surrounding the tax changes by prescribing the specific methods that must be used by regulators to account for the EDFIT benefits associated with plant balances, avoiding some controversy over the way that those amounts get returned to ratepayers.

Under Generally Accepted Accounting Principles ("GAAP"), the general rule is that when a change in the tax rate is enacted into law, the effects of the change must be reported in the period that includes the "enactment date."[5/] The normalization requirements for EDFIT in IRC § 168(i)(9), however, provide an exception to that general rule for public utilities.

For business enterprises other than a public utility, the change in tax rate results in material balance sheet impacts. For a non-utility business enterprise, deferred tax liabilities

[4/] See, e.g., PLR 200743030.

[5/] See Financial Accounting Standards Board ("FASB"), Statement of Financial Accounting Standards No. ("SFAS") 109, Accounting for Income Taxes ¶ 27; See also FASB Accounting Standards Codification ("ASC") 740-25-47.

and assets must be revalued at the new tax rate. Most utilities have net deferred tax liability balances, which represent funds in the utility's possession being held in reserve to pay for taxes the utility must pay in the future. Thus, if the tax rate declines, the tax liability balance declines, resulting in the recognition of a gain, similar to the gain that occurs when the principal balance of a loan is forgiven. For non-utilities, this gain flows through the income statement in the current period, in one lump-sum.

For public utilities, however, the treatment is different. When implementing the normalization requirements of IRC § 168(i)(9)—a rare instance where the Internal Revenue Service may exercise authority over the specific ratemaking methodology that state regulatory commissions use to establish public service rates—the balance sheet gains associated with the change in tax rate must remain on the public utility's balance sheet and be considered in rate base as an excess tax reserve, i.e., EDFIT. Further, rather than recording those benefits in one lump-sum, as required under GAAP, this ratemaking treatment requires the utility to recognize the financial gains associated with the lower tax rate over an extended period of time.

The amortization schedule is generally intended to correspond to the period over which the book-tax differences underlying EDFIT are expected to reverse, and two general methods are available to amortize the excess reserves—the ARAM and an Alternative Method.[6/] The ARAM methodology is computationally detailed and requires the utility to amortize the EDFIT reserve by plant vintage, ratably in proportion to the reversal of the book-tax differences underlying the EDFIT reserve. Provided the utility possesses the vintage data necessary to

[6/] The IRS has historically referred to the "Reverse South Georgia Method," although I used a generic term, Alternative Method, as used in the TCJA.

perform the ARAM method, the utility must use the ARAM when establishing rates. If the vintage data is not available, the utility must use the Alternative Method. Under the Alternative Method, EDFIT is reversed based on the weighted average life or composite rate used to compute depreciation for, or ratably over the remaining regulatory life of the property.

Q. DO THE IRS NORMALIZATION REQUIREMENTS APPLY TO ALL DEFERRED TAX BALANCES?

A. No. The IRS normalization requirements apply only to deferred tax balances associated with the use of accelerated depreciation—both the Modified Accelerated Cost Recovery System ("MACRS") and bonus depreciation—in IRC § 168k. Accordingly, normalization accounting methods outlined in the TCJA only apply to deferred tax balances associated with utility plant. Those deferred tax balances are often referred to as being *protected*.

With respect to the other deferred tax balances, those are often referred to as *unprotected*, since state Commissions, through the use of regulatory accounting, have greater leeway in determining how the gains on those EDFIT balances get returned to ratepayers.

Q. DID CASCADE CONSIDER EDFIT IN ITS FILING?

A. Yes. In its operating results Cascade did include $560,266 in reversal in income tax expense. Cascade's filing, however, does not identify the Oregon balances associated with the excess tax reserve accounts, or the amortization schedule. Of this EDFIT reversal, $382,556 is protected, and $177,710 is unprotected.

Q. DOES CASCADE PROVIDE THE DATA NECESSARY TO SUPPORT ITS CALCULATION OF THE ARAM?

A. No. Cascade has not provided the data necessary to support the calculation of the ARAM which I understand is being done using the PowerTax software. In Oregon, we use composite depreciation rates to determine the amount of book reserves. The composite rates are applied by FERC account and are not meant to assign any particular amount of accumulated depreciation to any particular vintage. The reserves are assigned to the surviving vintages on a theoretical basis using the shape of the survivor curve to determine the portion of each vintage that has been reserved. The PowerTax modules appear to be making an assumption that reserves have accumulated to the vintages in proportion to book values, which is not how the depreciation study operates.

Q. HAVE YOU QUANTIFIED THE IMPACT OF USING THE ALTERNATIVE METHOD?

A. Yes. Using the 3.04% composite depreciation rate from Cascade's 2015 depreciation study, I have estimated annual EDFIT reversals of $282,372 using the Alternative Method, which the IRS explicitly allows for utilities that use composite depreciation rates. This amount is slightly less than the amount Cascade calculated in Power Tax.

Q. WHY IS ALTERNATIVE METHOD IS PREFERABLE?

A. Even if the Alternative Method is less than the ARAM, there are many reasons the Alternative Method is preferable. The Alternative Method does not vary year to year and is thus preferred from that perspective. In addition, under the ARAM it is possible for significant amounts to be lost through the timing of rate cases and varying level of amortization that occur year to year.

Theoretically, utilities should still be reversing small amounts of EDFIT that were incurred as a result of the 1986 tax reform, but for many utilities that amortization is no longer being applied. Using the Alternative Method is preferred because it is simpler, easier to verify and results in a more consistent return of these ratepayer moneys.

Q. WHAT AMORTIZATION PERIOD HAS CASCADE USED FOR THE UNPROTECTED BALANCES?

A. Cascade appears to be amortizing those balances over ten years. While a longer period may be appropriate in some cases, given the scope of Cascade's operations in Oregon, a shorter period is preferred from a ratepayer perspective. The book-tax differences underlying the unprotected EDFIT reversal typically reverse over a relatively short period of time, often annually, and for that reason, shorter periods are commonly used for returning the unprotected balances.

Q. WHAT DO YOU RECOMMEND?

A. Subject to further review of Cascade's calculations, I recommend the Commission adopt a fixed rate of amortization for protected EDFIT. Rounding to post-tax protected EDFIT reversals of $300,000, which would be applied in rates until the balance is exhausted, is appropriate and consistent with IRS guidance on the matter. This amortization is slightly less than the Company's proposal, but offers the benefit of being stable over time. Further, I recommend adopting a two-year amortization, beginning April 1, 2019, to return the unprotected EDFIT balances, for the reasons discussed above. Adopting this approach results in an increase in the EDFIT reversal by approximately $610,658, and a corresponding revenue requirement reduction of $733,184.

c. <u>Interim Period Tax Savings</u>

Q. DID CASCADE CONSIDER THE INTERIM PERIOD TAX SAVINGS OVER THE PERIOD JANUARY 1, 2018 THROUGH APRIL 1, 2019 IN ITS RATE FILING?

A No. Cascade will recognize significant savings over the Interim Period in connection with the TCJA. While Staff filed a deferral application on December 29, 2017 to ensure these savings are captured for the benefit of customers, no determination has been made yet regarding when these savings will be returned. Because these savings can now be calculated with reasonable accuracy, I recommend that it begin to be passed back to customers at the start of the rate-effective period for this case. Any delay in the amortization of these deferred amounts will result in unnecessary rate fluctuations.

Q. WHAT IS BEING DEFERRED WITH RESPECT TO THE TCJA TAX SAVINGS?

A. It is important to recognize that the Interim Period deferral is concerned with the normalized revenue requirement impact of the TCJA on rates, and not the actual taxes that the utility is paying in the Interim Period. Administratively, it was impossible for the Commission to require every utility to file for new rates taking into consideration the TCJA on January 1, 2018, within the ten days or so from when the legislation was signed. Thus, working under the assumption that a utility's current rates provided it with the opportunity for a reasonable return, the deferral measures the rate change that would have been necessary to provide the utility with the same return on equity as if the tax rate had not been enacted.

Basing the deferral on actual taxes paid is arbitrary because those actual taxes depend on non-normal conditions, as well as the efficacy with which the utility operates its business. That sort of view would be particularly absurd for Cascade, since it pays no federal income taxes.

Q. HOW DID YOU DETERMINE THE IMPACT OF RESTATING TAX EXPENSE IN THE DEFERRAL PERIOD?

A. I used the rate base approach to determine the amount of revenues necessary to provide the utility with the same return on equity as if the tax rate had not been enacted. The tax impact on current rates is determined using Cascade's current level of rate base and cost of capital.

Under this method the "pre-tax" return on equity is used to determine the portion of revenues dedicated to paying federal income taxes, as show in the following formula:

RB * ROE / (1-T) * E% = Revenues for Taxes

Where: RB = Rate Base; ROE = Return on Equity;

T = Marginal Composite Tax Rate, and; E% = Equity %.

The above calculation is performed first based on the old 35% federal tax rate, and then again based on the new 21% federal tax rate.[7] The difference represents the estimate the revenue requirement savings associated with the lower rate.

Q. HOW SHOULD THESE VALUES BE RETURNED TO RATEPAYERS?

A. I recommend using a two-year amortization period. I recommend that the utility's typical general rate case cycle be a primary consideration when establishing the amortization period, with a target of returning the Interim Period savings over two rate case cycles. This treatment will promote rate stability and make it easier for Cascade to possibly delay or forego its next rate case. It is also consistent with the amortization period agreed to by Portland General Electric.

Q. DO YOU RECOMMEND THAT THE INTERIM PERIOD DEFERRAL BE INCLUDED IN RATE BASE?

A. No. I recommend that the amortization be tracked outside of rate base and included in an account that accrues interest at Cascade's pre-tax cost of capital. Further, I recommend adopting a levelized amortization schedule that brings the balance to zero over the two-year

[7] These equate to composite tax rates of 39.9% and 27.0%, after considering Oregon state federal income taxes.

period. This is often referred to as a sinking fund schedule of amortization and is similar to the treatment of Trojan decommissioning costs.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My calculation can be found in Exhibit AWEC/102, Page 2 and 3. As detailed there, I calculate monthly tax savings of $107,921. I also include monthly reversals of protected EDFIT, which amounts to $25,000 per month. Over the 15-month period, these amounts accumulate to a pre-tax balance of 2,093,492. Using the sinking fund method over a two-year period beginning on April 1, 2019 results in annual amortization of $1,160,097, or a revenue requirement impact of $1,295,831 after considering revenue sensitive costs.

IV. RATE BASE

Q. WHAT ISSUES DID YOU IDENTIFY IN YOUR REVIEW OF CASCADE'S CAPITAL FORECAST?

A. I performed a high-level review of Cascade's capital forecast, and reviewed large discrete projects. Based on my review, I propose several adjustments. A major portion of the capital Cascade proposes is to accommodate growth. Notwithstanding, Cascade does not consider the impact of this growth in revenues in developing its revenue forecast, resulting in a fundamental mismatch between costs and revenues in the revenue requirement model. In addition, I propose to remove the Madras pipeline replacement project due to inconsistencies with respect to the capital forecast amount and the likelihood that the project will be completed in time to be reviewed in this proceeding. Further, I recommend reducing gross plant for expected retirements over the test period. While retirements do not impact the net plant used in rate base, they do impact depreciation expense, and thus should be considered on the same basis that Cascade considers the incremental depreciation expenses associated with the new plant additions. Collectively, these capital adjustments reduce Cascade's rate base by $11,279,796.

I note that Cascade's capital forecast has been highly inconsistent throughout this proceeding. For example, in Cascade's initial filing, it proposed Oregon allocated investments of $22,410,919 in capital additions in 2018. Notwithstanding, a review of Cascade's most recent capital budget prepared in July 2018, which was provided in response to Staff Data Request 243, shows that Cascade forecasts transfers to plant of only $7,249,837. Many inconsistencies can be found within the budgets for individual projects as well. While I have not addressed all of those inconsistencies here, I may do so at a later stage in this proceeding in response to other parties' testimony.

a. <u>Growth Projects</u>

Q. WHAT PORTION OF THE CAPITAL ADDITIONS CASCADE PROPOSED ARE RELATED TO GROWTH?

A. Based on my review of the individual projects, at least $6,455,388 in forecast capital was related to growth.

Q. WHAT IS YOUR CONCERN WITH RESPECT TO THESE CAPITAL PROJECTS?

A. If a project is being built to accommodate growth, that means that the utility can expect additional revenues as a result of the new plant addition. These revenues are offsetting to the cost of the new plant addition.

Q. DID CASCADE ACCOUNT FOR THE ADDITIONAL REVENUES FROM GROWTH PROJECTS?

A. No. Cascade's use of end-of-period rate base means that the new plant additions are assumed to be in rate base for the entire year. Cascade did not make a similar assumption with respect to revenues derived from the new plant additions, however.

Q. WHAT DO YOU RECOMMEND?

A. To promote matching between costs and revenues, I recommend that the growth projects be excluded from test period revenue requirement.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Removing the growth-related capital additions results in an approximate $1,399,553 reduction to revenue requirement.

b. <u>Madras Project</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE MADRAS PROJECT.

A. The Madras Project is a pipe replacement project where Cascade has decided to replace the pipe because it lacks sufficient records related to the pipe. Cascade included $5,540,102 in capital related to this project in its capital forecast. The project is identified as FP-306997 and a project description was provided in response to Staff Data Request 134. The project replaces and upgrades a large section of pipe along the Crooked River natural grassland between Madras and Bend.

Q. WHY IS THE PROJECT BEING UNDERTAKEN?

A. Cascade stated that the pipe is old and that it has insufficient records with respect to the pipe.

Q. HOW MUCH IS THE PROJECT EXPECTED TO COST?

A. According to Cascade's response to Staff Data Request 134, the project was only expected to cost $2,494,592, which is less than one half of the amount that it has proposed to include in its capital budget. Further, in response to Staff Data Request 133, Cascade represented that the Madras project was a phased project and the first phase would only consist of $1,899,752 in capital.

Q. HAS CASCADE ADEQUATELY CONSIDERED ENVIRONMENTAL AND CULTURAL CONTINGENCIES WITH RESPECT TO THIS PROJECT?

A. The documentation makes no mention of such concerns, and thus, it is apparent that Cascade has not planned for them. For other utilities, the cost of environmental and cultural contingencies has been significant, particularly when not properly addressed in the planning and permitting phase of the project.

Q. WHEN IS THE PROJECT EXPECTED TO BE PLACED INTO SERVICE?

A. The project has not been placed into service yet, and Cascade represents that it expects the pipe to be operational by the end of the year. Given the weather conditions in Madras in January and the magnitude of the project, I find no evidence that the full project will be completed before the end of this construction cycle.

Q. WHAT DO YOU RECOMMEND?

A. Due to the gross inconsistencies with respect to the capital amount and the likelihood that the project will be completed in time to be reviewed in this proceeding, I recommend removing the Madras project in its entirety. Doing so results in an approximate $1,168,802 reduction to revenue requirement.

c. Plant Retirements

Q. DOES CASCADE CONSIDER PLANT RETIREMENTS WHEN DEVELOPING ITS REVENUE REQUIREMENT?

A. No. Cascade considers incremental depreciation, as well as plant additions, but does not consider the effects of forecast plant retirements. While plant retirements have no impact on rate base, since they are applied as a reduction to both gross plant and accumulated reserve, retirements do have an impact on depreciation expenses.

Q. WHAT LEVEL OF RETIREMENTS DO YOU PROPOSE FOR THE TEST PERIOD?

A. To estimate the impact of this adjustment, I used the level of retirements for 2016 that was reported in response to Staff Data Request 130.[8] I took the $5,560,629 in retirements in 2016 and multiplied that by the 3.04% composite depreciation rate to determine the effects of these retirements in the test period. After considering the effects on accumulated depreciation, the impact of this adjustment is a $168,037 reduction to revenue requirement.

V. CLASS COST OF SERVICE STUDY

Q. WHAT ARE YOUR CONCERNS WITH CASCADE'S CLASS COST OF SERVICE STUDY?

A. I have a number of concerns with respect to the class cost of service study. Cascade's suggestion that Schedule 163 customers are well below parity is simply incorrect, and its proposal to allocate the entire increase only to Schedules 101, 105 and 163 is unjustified and arbitrary. Cascade's cost of service study is flawed, inconsistent with how it proposes to set rates and should be rejected.

---

8 See file tilted OPUC-130 AIR-25 Asset-1201 12-2016

Q. HOW IS THE STUDY INCONSISTENT?

A. For purposes of setting rates, Cascade assumes that a special contract customer on Schedule 902-2 will migrate to the Schedule 163 general transportation rate. Notwithstanding, when determining which rate classes to allocate the proposed revenue requirement increase, Cascade's study did not consider the Schedule 902-2 customer cost and revenues in determining the cost of service for Schedule 163 rates.

Q. WHAT DOES THE ANALYSIS SHOW IF CORRECTED?

A. If the Schedule 902-2 customer is included with Schedule 163 in the cost of service study, in a manner consistent with Cascade's revenue forecast, it shows that Schedule 163 transportation rates are actually above parity by 22%. As detailed in Exhibit AWEC/108, the cost to revenue ratio for Schedule 163 is 122%, if the Schedule 902-2 revenues are handled in a consistent manner.

Q. DOES THE STUDY MAKE ANY SENSE AS DEVELOPED?

A. No. Treating the Schedule 902-2 customer as a cost of service customer, and then separating that customer from the cost of service study makes the results of the study inviable. Notwithstanding, I have a number of other concerns with respect to the study, which also demonstrate that Cascade's approach is flawed. For example, Cascade's study allocates commodity investment costs of $19,247,882 to transportation customers, but not to special contract customers, which if corrected further increases the parity ratio of transportation customers on Schedule 163. If the Commodity investment is removed from Schedule 163, the study shows a party ratio of 118% for Schedule 163, holding all other factors constant.

Q. IS THE STUDY BASED ON A VIABLE LOAD STUDY?

A. No. AWEC is also concerned that Cascade has not undertaken a customer-level load study to inform its cost of service study, and for that reason the study results should be given little weight.

Q. WHAT DO YOU RECOMMEND?

A. If Cascade's study is corrected, it shows that Schedule 163 customers are paying significantly greater than their share of allocated costs. Accordingly, I recommend that in no circumstance should a rate increase be applied Schedule 163. Notwithstanding, because I am recommending a rate reduction I believe it is reasonable to apply the reduction on an equal percent of margin basis. If the Commission were to approve a rate increase, however, I recommend it be applied on an equal percent of margin to all classes other than Schedules 163 and 111.

VI. SAFETY TRACKER MECHANISM

Q. WHAT ISSUES DID YOU IDENTIFY WITH CASCADE'S PROPOSED SAFETY TRACKER MECHANISM?

A. With Cascade's proposed safety tracker mechanism, it seeks to depart from the traditional form of cost recovery available for regulated utilities in Oregon for safety-related improvements, and is asking to implement a disfavored form of single-issue ratemaking, which results in an upside only to Cascade to the detriment of its customers. Cascade has not justified the proposed mechanism and has failed to identify any reason why traditional ratemaking is not sufficient to recover the expenditures associated with its capital investment program.

Q. WHAT IS THE PURPOSE OF CASCADE'S PROPOSED MECHANISM?

A. Cascade has the obligation to provide safe and reliable service regardless of whether it has an approved safety tracker. The safety tracker is really just a cost recovery mechanism that eliminates regulatory lag. Cascade argues that the proposed safety tracker mechanism is part of its efforts to provide safe and reliable service.

Q. WHAT IS THE APPROPRIATE WAY CASCADE SHOULD RECOVER ITS COSTS RELATED TO SAFETY?

A. As mentioned above, Cascade has the obligation to provide safe and reliable service, and AWEC supports Cascade's endeavors to do so. Cascade's prudently incurred safety related costs are properly recovered through traditional ratemaking processes. In a general rate case, a holistic review of Cascade's costs, revenues, and rate base can take place, and it is that process that can best determine whether overall rates are just, reasonable and in the public interest.

Q. WHAT IS IT ABOUT CASCADE'S APPROACH THAT IS COUNTER TO THAT TRADITIONAL METHOD?

A. Cascade's approach here constitutes single-issue ratemaking. Single-issue ratemaking occurs when utility rates are adjusted in response to a change in cost or revenue items considered in isolation. By considering an operating expense or rate base item in isolation, single-issue ratemaking ignores other factors that otherwise influence the utility's operating results, some of which could, if properly considered, move revenue requirements in the opposite direction from the single-issue change. Single issue ratemaking in general is beneficial to shareholders and harmful to customers.

Because single-issue ratemaking focuses on specific costs in isolation, the Commission should view such proposals with great caution.

Q. ARE THERE SITUATIONS WHERE SINGLE-ISSUE RATEMAKING IS WARRANTED?

A. Yes, but this is not such a situation. There are limited situations, such as a change in federal tax rates or significant changes in fuel costs, in which singling out certain items for immediate rate recovery, tracker-increases, or deferred recovery is appropriate. As a general matter, however, such cases involve costs which are beyond the control of the utility and are not appropriate for routine investments such as those for safety improvements. None of the above situations exist.

Q. SHOULD CASCADE BE ALLOWED TO RECOVER ITS PRUDENTLY INCURRED SAFETY COSTS?

A. Yes. To be clear, AWEC's position is not that Cascade cannot recover prudently incurred safety costs. Rather, the question is "when" such cost recovery of prudently incurred safety costs is appropriate (either through trackers or in a rate proceeding). Cascade has the obligation to operate safely and to make investments to secure and maintain its gas distribution system. A fundamental part of the regulatory compact is that utilities must maintain their systems and be in compliance with state and federals laws, which change from time to time.

Q. WHY IS IT FAIR TO REVIEW THESE TYPES OF ISSUES IN RATE PROCEEDINGS RATHER THAN APPROVE THE SAFETY TRACKER?

A. The rate setting process grants local distribution companies ("LDC") a considerable depreciation expense at the time new rates are set, and the rate base is also established. LDCs also earn a return on their established rate base, even though the rate base declines with depreciation. That added revenue should provide the funds necessary to make capital investments without harming the utility's earnings, even if revenues are flat. There has been no showing that infrastructure investments in the coming years will so exceed the allowed depreciation expense and the financial incentive that comes from having a fixed rate base. Nor has Cascade presented evidence that regulatory lag is eroding earnings due to enhanced investment in safety related improvements.

It is further noteworthy that Cascade's single-issue ratemaking request has to do with the recovery of capital associated with utility plant. Under Oregon's used and useful statute, special considerations must be taken for plant and the Cascade's proposal may not allow for those considerations.

Q. ARE THERE OTHER ISSUES WITH CASCADE'S PROPOSED TRACKER MECHANISM?

A. Yes. Cascade's mechanism conflicts with the used and useful standard because it would result in a return on a level of rate base exceeding the used and useful level. While Cascade proposes to track additions to rate base, it excludes the corresponding subtractions from rate base that will occur after the last general rate case. In contrast to capital additions, retirements of existing plant necessary for Cascade's safety program will not be tracked individually in rate base. To account for retirements, the depreciation reserve amount increases in a manner corresponding to the level of retirements expected in a particular period based on the life characteristics of the utility's property. While Cascade accounts for accumulated depreciation reserves on the new plant additions, the proposed mechanism does not consider the incremental depreciation reserves that have accrued on existing plant in service. By excluding incremental depreciation reserves on existing plant in service, Cascade will ignore the revenue requirement effect of retiring existing plant in order to implement its safety program, effectively providing it with a return on property that has been taken out of service.

In addition, the proposal for incremental depreciation expenses in the filing would also inflate Cascade's return of its investment. The filing does not consider the way that plant retirements have impacted gross plant levels since Cascade's last general rate case. While an individual plant retirement has no impact on overall rate base, the retired property is removed from, and does impact, gross plant balances. In rate base, the retirement is offset by corresponding reduction to depreciation reserves. In net operating income, however, depreciation expenses are calculated based on gross plant, and the retirement of existing plant results in a corresponding reduction to depreciation expense. Since Cascade does not consider the impact of plant retirements on depreciation expense, approval of the proposed mechanism would result in Cascade over-recovering its investment in utility plant.

Q. CAN YOU PROVIDE EXAMPLES OF HOW CASCADE WOULD OVER-RECOVER IF THE SAFETY TRACKER IS APPROVED?

A, Yes. Table 3 below helps to illustrate this point.

TABLE 3
Base Rate vs. Tracker Recovery Illustration ($000)

	Test Year	Additions*	Depr. Resrvs.	Retrmnts.	Option 1 Rate Case	Option 2 Tracker
	(a)	(b)	(c)	(d)	(e) = ∑ (a):(d)	(f) = ∑ (a):(b)
Rate Base						
Gross Plant	25,000	1,000		(500)	25,500	26,000
ACC Dep	(7,500)	(25)	(625)	500	(7,650)	(7,525)
Net Plant	17,500	975	(625)	-	17,850	18,475
Working Capital	500				500	500
ADIT	(1,125)				(1,125)	(1,125)
Rate Base	16,875	975	(625)	-	17,225	17,850
Net Oper. Inc. (10%)	1,688	98	(63)	-	1,723	1,785
Income Tax	224				229	237
Depr. Exp. (2.5%)	625	25	-	(13)	638	650
Revenue Req.	2,537	123	(63)	(13)	2,589	2,659
Relative Increase					**2.1%**	**4.8%**

* Represents Safety Tracker Revenues

In this example, base rates are set in year 1 through a rate case. The rates are set to recover the utility's net rate base investments. Then we move to the year following the year 1 rate case, and the system safety additions are added in two different ways (Option 1—Rate Case) and Option 2 (Tracker). Option 1 continues base rate cost recovery with the safety improvements through a rate case filing as shown in the second column from the right. Option 1 includes the impact of the additions, as well as the offsetting impacts associated with incremental depreciation reserves and retirements. In Option 2, base rates do not change but a tracker filing for new safety investments has been put into place (no rate case), as shown in the last column on the right.

In Option 1, the incremental plant investment is added to rate base and accumulated depreciation reserve and ADIT are reducing rate base. The "net" increase in rate base reflects the rate base additions net of reductions. Rates are set based on net plant changes.

In Option 2, base rates are not changed, and no rate proceeding is assumed to take place. A tracker charge is imposed for all incremental or new plant investment. Here, the combination of base rate set in the last rate case and the addition of the tracker surcharge results in customers paying more than the "net" change in the utility's plant investment. The reduction in plant caused by increases in accumulated depreciation are not reflected in either base rates or the tracker. The tracker is intended to capture all increases in new safety investments, without any offset. In other words, in Option 2, base rates and the tracker reflect plant additions, but do not reflect plant reductions.

In summary, customers pay more through trackers than they would have paid through rate case recovery because all charges are not synchronized to accurately reflect changes in "net" plant. Absent extraordinary circumstances that warrant a safety tracker, this is not fair, just or reasonable.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

In the Matter of	)
	)
CASCADE NATURAL GAS CORPORATION,	)
	)
Request for a General Rate Revision.	)

EXHIBIT 101

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

September 27, 2018

QUALIFICATION STATEMENT

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I have a Master of Accounting degree from the University of Utah. After obtaining my master's degree, I worked at Deloitte in San Jose, California, where I specialized in performing research and development tax credit studies. I later worked at PacifiCorp as an analyst involved in power cost forecasting. I currently provide services to utility customers on matters such as revenue requirements, power cost forecasting, and rate design. I have sponsored testimony in several regulatory jurisdictions around the United States, including before the Oregon Public Utilities Commission.

Q. PLEASE PROVIDE A LIST OF YOUR REGULATORY APPEARANCES.

A. I have sponsored testimony in the following regulatory proceedings:

- <u>In re Avista Corporation, dba Avista Utilities, Application to Revise Book Depreciation Rates and Request Deferred Accounting,</u> Or.PUC Docket No. UM 1933.
- <u>In re PacifiCorp, dba Pacific Power, 2019 Transition Adjustment Mechanism,</u> Or.PUC Docket No. UE 323
- <u>In re Portland General Electric Company Request for a General Rate Revision,</u> Or.PUC Docket No UE 335
- <u>In re Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision,</u> Or.PUC Docket No. UG 344.
- <u>In re Cascade Natural Gas Corporation Request for a General Rate Revision,</u> Wa.UTC, Docket No. UE-170929.
- <u>In the Matter of Hydro One Limited, Application for Authorization to Exercise Substantial Influence over the Policies and Actions of Avista Corporation</u>, Or.PUC, Docket No. UM 1897.
- <u>In re Pacific Power & Light Company 2016 Power Cost Adjustment Mechanism,</u> Wa.UTC, Docket No. 170717.
- <u>In re the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Request to Construct Wind Resource and Transmission Facilities,</u> Ut.PSC, Docket No. 17-035-040.

- In re The Application of PacifiCorp dba Rocky Mountain) Power For A Certificate Of Public Convenience and Necessity and Binding Ratemaking Treatment For New Wind And Transmission Facilities, Id.PUC Case No. PAC-E-17-07.
- In re Avista Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-170485 (Cons.).
- Application of Nevada Power Company d/b/a NV Energy for Authority to Adjust its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and For Relief Properly Related Thereto, Nv.PUC, Docket No. 17-06003 (Cons.).
- In the Matter of PacifiCorp, dba Pacific Power, 2016 Power Cost Adjustment Mechanism, Or.PUC, Docket No. UE-327.
- In re the 2018 General Rate Case of Puget Sound Energy, Wa.UTC, Docket No. 170033 (Cons.).
- In re PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 323.
- In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 319.
- In re Portland General Electric Company, Application for Transportation Electrification Programs, Or.PUC, UM 1811.
- In re Pacific Power & Light Company, Application for Transportation Electrification Programs, Or.PUC, Docket No. UM 1810.
- In re the Public Utility Commission of Oregon, Investigation to Examine PacifiCorp, dba Pacific Power's Non-Standard Avoided Cost Pricing, Or.PUC, Docket No. UM 1802.
- In re Pacific Power & Light Co., Revisions to Tariff WN U-75, Advice No. 16-05, to modify the Company's existing tariffs governing permanent disconnection and removal procedures, Wa.UTC, Docket No. UE-161204.
- In re Puget Sound Energy's Revisions to Tariff WN U-60, Adding Schedule 451, Implementing a New Retail Wheeling Service, Wa.UTC, Docket No. UE-161123.
- 2018 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-18.
- In re Portland General Electric Company Application for Approval of Sale of Harborton Restoration Project Property, Or.PUC, Docket No. UP 334 (Cons.).
- In re An Investigation of Policies Related to Renewable Distributed Electric Generation, Ar.PSC, Matter No. 16-028-U.
- In re Net Metering and the Implementation of Act 827 of 2015, Ar.PSC, Matter No. 16-027-R.

- In re the Application of Rocky Mountain Power for Approval of the 2016 Energy Balancing Account, Ut.PSC, Docket No. 16-035-01
- In re Avista Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-160228 (Cons.).
- In re the Application of Rocky Mountain Power to Decrease Current Rates by $2.7 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 and to Increase Rates by $50 Thousand Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-292-EA-16.
- In re PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 307.
- In re Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125), Or.PUC, Docket No. UE 308.
- In re PacifiCorp, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol, Or.PUC, UM 1050.
- In re Pacific Power & Light Company, General rate increase for electric services, Wa.UTC, Docket No. UE-152253.
- In The Matter of the Application of Rocky Mountain Power for Authority of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $32.4 Million Per Year or 4.5 Percent, Wy.PSC, Docket No. 20000-469-ER-15.
- In re Avista Corporation, General Rate Increase for Electric Services, Wa.UTC, Docket No. UE-150204.
- In re the Application of Rocky Mountain Power to Decrease Rates by $17.6 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 to Decrease Rates by $4.7 Million Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-472-EA-15.
- Formal complaint of The Walla Walla Country Club against Pacific Power & Light Company for refusal to provide disconnection under Commission-approved terms and fees, as mandated under Company tariff rules, Wa.UTC, Docket No. UE-143932.
- In re PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 296.
- In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 294.
- In re Portland General Electric Company and PacifiCorp dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation, Or.PUC, Docket No. UM 1662.
- In re PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction, Or.PUC, Docket No. UM 1712.

- In re Public Utility Commission of Oregon, Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity, Or.PUC, Docket No. UM 1719.
- In re Portland General Electric Company, Application for Deferral Accounting of Excess Pension Costs and Carrying Costs on Cash Contributions, Or.PUC, Docket No. UM 1623.
- 2016 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-16.
- In re Puget Sound Energy, Petition to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes, Wa.UTC, Docket No. UE-141368.
- In re Pacific Power & Light Company, Request for a General Rate Revision Resulting in an Overall Price Change of 8.5 Percent, or $27.2 Million, Wa.UTC, Docket No. UE-140762.
- In re Puget Sound Energy, Revises the Power Cost Rate in WN U-60, Tariff G, Schedule 95, to reflect a decrease of $9,554,847 in the Company's overall normalized power supply costs, Wa.UTC, Docket No. UE-141141.
- In re the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $36.1 Million Per Year or 5.3 Percent, Wy.PSC, Docket No. 20000-446-ER-14.
- In re Avista Corporation, General Rate Increase for Electric Services, RE, Tariff WN U-28, Which Proposes an Overall Net Electric Billed Increase of 5.5 Percent Effective January 1, 2015, Wa.UTC, Docket No. UE-140188.
- In re PacifiCorp, dba Pacific Power, Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market, Or.PUC, Docket No. UM 1689.
- In re PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 287.
- In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 283.
- In re Portland General Electric Company's Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU), Or.PUC, Docket No. UE 286.
- In re Portland General Electric Company 2014 Schedule 145 Boardman Power Plant Operating Adjustment, Or.PUC, Docket No. UE 281.
- In re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out (adopting testimony of Donald W. Schoenbeck), Or.PUC, Docket No. UE 267.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

	)
In the Matter of	)
	)
CASCADE NATURAL GAS CORPORATION,	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT 102

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

September 27, 2018

Cascade Natural Gas Corporation
Gas Revenue Requirement Summary ($000)
In Thousands

Line	Adj. No.	Description	Cumulative Results: Net Oper. Income	Cumulative Results: Rate Base	Cumulative Results: Rev. Req. Def. / (Suf.)	Impact of Adjustments: Pre-Tax Net Oper. Income	Impact of Adjustments: Net Oper. Income	Impact of Adjustments: Rate Base	Impact of Adjustments: Rev. Req. Def. / (Suf.)
1		**Cascade Initial Filing**	**6,506**	**111,129**	**2,311**				
Cost of Capital Adjustments									
2		Cost of Debt	6,506	111,129	2,224				(86)
3		Correct Conversion Factor	6,506	111,129	2,219				(6)
Corporate Cost Allocation									
4	A1	Corporate Overhead Rate	6,970	111,129	1,564	*636*	*465*	-	(655)
5	A2	Utility Group Allocations	6,980	111,129	1,550	*13*	*9*	-	(13)
6	A3	Incentives	7,126	111,129	1,344	*200*	*146*	-	(206)
7	A4	Dues and Subscriptions	7,133	111,129	1,335	*9*	*7*	-	(9)
8	A5	Legal Expenses	7,174	111,129	1,276	*57*	*42*	-	(59)
9	A6	Taxes Other Than Income Taxes	7,196	111,129	1,245	*30*	*22*	-	(31)
Tax Issues									
10	A7	Effective State Tax Rate	7,268	111,129	1,079	91	*72*	-	(166)
11	A8	Excess Deferred Federal Income Taxes ("EDFIT")	7,879	111,740	346		611	611	(733)
12	A9	Interim Period Deferral	8,795	111,740	(950)	1,160	*916*	-	(1,296)
Capital Adjustments									
13	A10	Remove Growth Projects	9,355	105,831	(2,349)	722	*560*	(5,909)	(1,400)
14	A11	Madras Project	9,779	100,291	(3,518)	546	*424*	(5,540)	(1,169)
15	A12	Retirements	9,910	100,460	(3,686)	169	*131*	169	(168)
18		Interest Sync.	9,844	100,460	(3,593)	-	*(66)*	-	93
					Total Adjustments:	***3,634***	***3,404***	***(10,669)***	***(5,997)***

Cascade Natural Gas Company
Calculation of the Deferral Related to Excess Taxes Collected in Rates Over the Period January 1, 2018 through April 1, 2019
In Thousands

Line				
1	**Restating Adjustment Calculation Using Gross-up Method:**			
2	Rate Base	YE 2017	$93,384	
3	Equity %		50.00%	
4	Equity Portion of Rate Base	Line 2 * Line 3	46,692	
5	Return On Equity		9.40%	
6	Pretax Return On Equity (35% Rate)	Line 5 * (1 - 39.9%	15.65%	8.63% Pre-tax Cost of Capital
7	Pretax Equity Returns Required (35% Rate)	Line 4 * Line 5	7,307.76	
8	Pretax Return on Equity (21% Rate)	Line 7 * (1 - 27.0%	12.88%	
9	Pretax Equity Return (21% Rate)	Line * Line 7	6,012.72	
10	**Annual Equity Return Differential (35% to 21% Rate)**	Line 9 * Line	**(1,295)**	

Line	**Monthly Deferral Calculation**		**1/1/2018**	**2/1/2018**	**3/1/2018**	**4/1/2018**	**5/1/2018**	**6/1/2018**	**7/1/2018**	**8/1/2018**	**9/1/2018**	**10/1/2018**	**11/1/2018**	**12/1/2018**	**1/1/2019**	**2/1/2019**	**3/1/2019**	**Total**
11																		
12	Monthly Return Diff. at Restated 21 % Tax Rate	Line 10 / 12	(108)	(108)	(108)	(108)	(108)	(108)	(108)	(108)	(108)	(108)	(108)	(108)	(108)	(108)	(108)	(1,619)
13	Monthly Protected EDFIT Amortization	Tab 11	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(250)
14	Monthly EDFIT Amortization (Pretax)	Line 13 / (1-21%)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(316)
15	Total Deferred Amounts	Line 13 + Line 14	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(1,396)
16	Carrying Charge (Per Mo. at Pre-tax ROR)		0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	
17	Balance																	
18	Beginning Balance		-	(140)	(279)	(419)	(558)	(698)	(837)	(977)	(1,117)	(1,256)	(1,396)	(1,535)	(1,675)	(1,814)	(1,954)	
19	Deferral	Line 15	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	
20	Interest	Line 16 * (Line 17 + Line 18 / 2)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
21	Ending Balance	∑ Lines 18:20	(140)	(279)	(419)	(558)	(698)	(837)	(977)	(1,117)	(1,256)	(1,396)	(1,535)	(1,675)	(1,814)	(1,954)	(2,093)	

Cascade Natural Gas Company
Calculation of the Deferral Related to Excess Taxes Collected in Rates Over the Period January 1, 2018 through April 1, 2019
In Thousands

Month	Beg Balance	Amortization	Interest Rate	Interest	Ending Balance	
5/1/2018	(2,093)	**97**	0.72%	(16)	(2,013)	
6/1/2018	(2,013)	*97*	0.72%	(16)	(1,932)	
7/1/2018	(1,932)	*97*	0.72%	(15)	(1,851)	
8/1/2018	(1,851)	*97*	0.72%	(15)	(1,769)	
9/1/2018	(1,769)	*97*	0.72%	(14)	(1,687)	
10/1/2018	(1,687)	*97*	0.72%	(14)	(1,603)	
11/1/2018	(1,603)	*97*	0.72%	(13)	(1,520)	
12/1/2018	(1,520)	*97*	0.72%	(12)	(1,435)	
1/1/2019	(1,435)	*97*	0.72%	(12)	(1,350)	
2/1/2019	(1,350)	*97*	0.72%	(11)	(1,265)	
3/1/2019	(1,265)	*97*	0.72%	(10)	(1,179)	
4/1/2019	(1,179)	*97*	0.72%	(10)	(1,092)	
5/1/2019	(1,092)	*97*	0.72%	(9)	(1,004)	
6/1/2019	(1,004)	*97*	0.72%	(9)	(916)	
7/1/2019	(916)	*97*	0.72%	(8)	(828)	
8/1/2019	(828)	*97*	0.72%	(7)	(738)	
9/1/2019	(738)	*97*	0.72%	(7)	(648)	
10/1/2019	(648)	*97*	0.72%	(6)	(558)	
11/1/2019	(558)	*97*	0.72%	(5)	(466)	
12/1/2019	(466)	*97*	0.72%	(5)	(374)	
1/1/2020	(374)	*97*	0.72%	(4)	(282)	
2/1/2020	(282)	*97*	0.72%	(3)	(189)	
3/1/2020	(189)	*97*	0.72%	(3)	(95)	
4/1/2020	(95)	*97*	0.72%	(2)	(0)	<-Goal Seek to Zero

Annual Amortization (Pre-tax): **1,160**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

	)
In the Matter of	)
	)
CASCADE NATURAL GAS CORPORATION,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT 103

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

September 27, 2018

CASCADE NATURAL GAS CORPORATION
ALLIANCE OF WESTERN ENERGY CONSUMERS
General Rate Case
UG 347

AWEC DATA REQUEST NO. 5

Date prepared: 8/15/18

Preparer: Becky Beach

Contact: Pamela Archer

Telephone: (509)-734-4591

Please provide copies of Cascade's 2017 tax provision workpapers.

Response:

See attached files.

AWEC-5 Confidential 2017 Rpt 216 – Plant Deferred tax current activity.pdf
AWEC-5 Confidential 2017 Rpt 248 – Plant Beginning Timing Difference.pdf
AWEC-5 Confidential 2017 Rpt 249 – Plant Ending Timing Difference.pdf
AWEC-5 Confidential 2017 Rpt 257 – Plant Deferred Tax Rollforward.pdf
AWEC-5 Confidential 2017 Rpt 51013 – Current Provision-all.pdf
AWEC-5 Confidential 2017 Rpt 51024 – Account Activity Report by Month.xls
AWEC-5 Confidential 2017 Rpt 51050 – Deferred Tax Balance roll forward.pdf
AWEC-5 Confidential 2017 Rpt 54515 – Total Tax Analysis Report.pdf
AWEC-5 Confidential 2017 Rpt 54516 – Effective Tax Rate Report.pdf

Tax Provision Effect Tax Rate Report

00047-Cascade Natural Gas Co.
2017 Actuals CNGC
All Months
ACROSS OPERATING INDICATORS

		Current Period		Adjustments		Total	
		Total Tax	ETR %	Total Tax	ETR %	Total Tax	ETR %
Book Income		$20,807,215.88		$0.00		$20,807,215.88	
Tax Items		$0.00		$0.00		$0.00	
Book Income Before Income Taxes (Adjusted for Tax Items)		$20,807,215.88	100.0000%	$0.00	0.0000%	$20,807,215.88	100.0000%
Federal Income Taxes @ Statutory Rate		$7,282,525.56	35.0000%	$0.00	0.0000%	$7,282,525.56	35.0000%
State Taxes		$375,543.36	1.8049%	$0.00	0.0000%	$375,543.36	1.8049%
State Benefit of Fed/State Deduction		$0.00	0.0000%	$0.00	0.0000%	$0.00	0.0000%
Fed Benefit of State Tax Deduction		($131,440.18)	-0.6317%	$0.00	0.0000%	($131,440.18)	-0.6317%
Fed / Foreign Rate Differential		$0.00	0.0000%	$0.00	0.0000%	$0.00	0.0000%
Total Federal & State @ Statutory Rates		$7,526,628.74	36.1732%	$0.00	0.0000%	$7,526,628.74	36.1732%
Other Current Tax ETR Adjustments							
Current Year Current Tax State Rate Change Adjust		$0.00	0.0000%	($297.44)	0.0000%	($297.44)	-0.0014%
Current Year Current Tax Fed/For Rate Change Adjust		$0.00	0.0000%	$0.00	0.0000%	$0.00	0.0000%
CWIP							
UT0785	AFUDC DEBT - CAPITALIZED	$40,484.75	0.1946%	$63,990.00	0.0000%	$104,474.74	0.5021%
UT0786	AFUDC DEBT - INCURRED - FED	($34,836.56)	-0.1674%	($141,835.30)	0.0000%	($176,671.86)	-0.8491%
UT0787	AFUDC EQUITY - CAPITALIZED	$202,004.32	0.9708%	($15,371.05)	0.0000%	$186,633.28	0.8970%
UT0788	AFUDC EQUITY - INCURRED	($64,360.50)	-0.3093%	$0.00	0.0000%	($64,360.50)	-0.3093%
UT079	SECTION 174 COSTS - INCURRED	($106,114.04)	-0.5100%	($1,094,670.12)	0.0000%	($1,200,784.16)	-5.7710%
UT0794	CIAC - CAPITALIZED	($208,156.93)	-1.0004%	$465,089.92	0.0000%	$256,932.99	1.2348%
UT0795	CIAC - INCURRED	$67,927.01	0.3265%	$854,425.95	0.0000%	$922,352.96	4.4329%
UT0796	CPI - CAPITALIZED	($30,807.91)	-0.1481%	($57,283.74)	0.0000%	($88,091.65)	-0.4234%
UT0797	CPI - INCURRED	$26,713.53	0.1284%	$92,079.96	0.0000%	$118,793.49	0.5709%
UT0798	PLANT R&D - CAPITALIZED	$0.00	0.0000%	$541,083.96	0.0000%	$541,083.96	2.6005%
UT0799	PLANT R&D - INCURRED	$0.00	0.0000%	($541,083.96)	0.0000%	($541,083.96)	-2.6005%
Subtotal:		($107,146.33)	-0.5149%	$166,425.61	0.0000%	$59,279.28	0.2849%
Deferred Current							
UT0004	ST INCENTIVE ACCRUAL *NEW*	$22,925.17	0.1102%	$22.05	0.0000%	$22,947.22	0.1103%
UT0051	UNIFORM CAPITALIZATION *NEW*	$4,169.10	0.0200%	$0.11	0.0000%	$4,169.21	0.0200%
UT0160	CHARITABLE CONTRIBUTIONS	$0.00	0.0000%	$42,433.58	0.0000%	$42,433.58	0.2039%
UT0161	CHARITABLE CONTRIBUTIONS *NEW*	($3.27)	-0.0000%	($295.26)	0.0000%	($298.53)	-0.0014%

Tax Provision Effect Tax Rate Report

00047-Cascade Natural Gas Co.
2017 Actuals CNGC
All Months
ACROSS OPERATING INDICATORS

		Current Period		Adjustments		Total	
		Total Tax	ETR %	Total Tax	ETR %	Total Tax	ETR %
Deferred Current							
UT0201	BAD DEBTS EXPENSE *NEW*	$63,939.53	0.3073%	$0.17	0.0000%	$63,939.70	0.3073%
UT0280	VACATION PAY *NEW*	$261,542.72	1.2570%	$3.04	0.0000%	$261,545.76	1.2570%
UT0354	CUSTOMER ADVANCES *NEW*	$461,787.98	2.2194%	$22.92	0.0000%	$461,810.90	2.2195%
UT0355	PREPAID EXPENSES*	($42,835.93)	-0.2059%	($3.80)	0.0000%	($42,839.73)	-0.2059%
UT0391	PURCHASED GAS ADJUSTMENT *NEW*	($1,594,184.37)	-7.6617%	($5.78)	0.0000%	($1,594,190.15)	-7.6617%
UT0423	LEGAL RESERVE	$54,970.76	0.2642%	$7.09	0.0000%	$54,977.85	0.2642%
Subtotal:		($767,688.31)	-3.6895%	$42,184.11	0.0000%	($725,504.19)	-3.4868%
Deferred Non Current							
UT0142	PENSION EXPENSE *NEW*	($4,355,772.59)	-20.9340%	($3.71)	0.0000%	($4,355,776.30)	-20.9340%
UT0144	POSTRETIREMENT BENEFIT COSTS *NEW*	($795,418.38)	-3.8228%	($3.00)	0.0000%	($795,421.38)	-3.8228%
UT0313	RESTRICTED STOCK L/T *NEW*	$0.00	0.0000%	$45,687.85	0.0000%	$45,687.85	0.2196%
UT0372	UNAMORTIZED LOSS ON REACQUIRED DEBT *NEW*	($106,423.68)	-0.5115%	$0.00	0.0000%	($106,423.68)	-0.5115%
UT0384	MANUFACTURED GAS PLANT SITE - BREMERTON - REG ASSET *NE\	($2,209,550.88)	-10.6192%	($0.41)	0.0000%	($2,209,551.29)	-10.6192%
UT0385	MANUFACTURED GAS PLANT SITE - BREMERTON - LIABILITY *NEW'	$1,670,848.63	8.0301%	$26.24	0.0000%	$1,670,874.87	8.0303%
UT0386	MANUFACTURED GAS PLANT SITE - EUGENE - REG ASSET *NEW*	($261,528.69)	-1.2569%	($1.92)	0.0000%	($261,530.61)	-1.2569%
UT0387	MANUFACTURED GAS PLANT SITE - EUGENE - LIABILITY *NEW*	$212,654.24	1.0220%	$13.51	0.0000%	$212,667.75	1.0221%
UT0402	SUNNYSIDE REMEDIATION *NEW*	$9,738.71	0.0468%	$0.00	0.0000%	$9,738.71	0.0468%
UT0466	SISP/SERP EXPENSE *NEW*	$20,478.04	0.0984%	$1,233,323.97	0.0000%	$1,253,802.01	6.0258%
UT0470	DEFERRED PENSION & POST RETIREMENT EXPENSE - REG ASSET	$5,641,559.32	27.1135%	$38.60	0.0000%	$5,641,597.92	27.1137%
UT0471	DEFERRED PENSION & POST RETIREMENT EXPENSE - REG LIABILI	($5,962,449.63)	-28.6557%	($0.00)	0.0000%	($5,962,449.63)	-28.6557%
UT0486	INTERCOMPANY DEFERRED EMPLOYEE BENEFIT COSTS - REG ASS	($126,218.09)	-0.6066%	($4,925.79)	0.0000%	($131,143.87)	-0.6303%
UT0487	INTERCOMPANY DEFERRED EMPLOYEE BENEFIT COSTS - REG LIAI	$173,169.45	0.8323%	$5,181.32	0.0000%	$178,350.77	0.8572%
UT0510	MAOP COSTS - OR	($73,244.64)	-0.3520%	$0.00	0.0000%	($73,244.64)	-0.3520%
UT0511	MAOP COSTS - WA	($830,158.53)	-3.9898%	($0.00)	0.0000%	($830,158.53)	-3.9898%
Subtotal:		($6,992,316.73)	-33.6052%	$1,279,336.66	0.0000%	($5,712,980.08)	-27.4567%
Deferred Non Current Property							
UT0693	PLANT - FED	($152,442.17)	-0.7326%	($6,134.45)	0.0000%	($158,576.62)	-0.7621%
UT0694	PLANT - STATE	$27,652.60	0.1329%	($545.71)	0.0000%	$27,106.88	0.1303%
Subtotal:		($124,789.57)	-0.5997%	($6,680.16)	0.0000%	($131,469.73)	-0.6318%
Deferred Only Adjustments							
UT0980	EXCESS DEF NONPLANT - OTHER - FED	$8,134,747.18	39.0958%	$0.00	0.0000%	$8,134,747.18	39.0958%
UT0980	EXCESS DEF NONPLANT - RATE BASE - FED	($358,148.84)	-1.7213%	$0.00	0.0000%	($358,148.84)	-1.7213%
UT0980	EXCESS DEF NONPLANT - RATE BASE - STATE	$2,860.28	0.0137%	$0.00	0.0000%	$2,860.28	0.0137%
UT0980	EXCESS DEF PLANT - FED	$63,007.25	0.3028%	$0.00	0.0000%	$63,007.25	0.3028%
UT0980	OTHER DEF ONLY ADJ - FED	$0.00	0.0000%	($320,890.45)	0.0000%	($320,890.45)	-1.5422%
UT0980	OTHER DEF ONLY ADJ - INTERCO - FED	$0.00	0.0000%	$47,209.94	0.0000%	$47,209.94	0.2269%

Tax Provision Effect Tax Rate Report

00047-Cascade Natural Gas Co.
2017 Actuals CNGC
All Months
ACROSS OPERATING INDICATORS

		Current Period		Adjustments		Total	
		Total Tax	ETR %	Total Tax	ETR %	Total Tax	ETR %
Deferred Only Adjustments							
UT0984	R&D TAX CREDIT CARRYFORWARD	$0.00	0.0000%	$130,245.00	0.0000%	$130,245.00	0.6260%
Subtotal:		$7,842,465.87	37.6911%	($143,435.51)	0.0000%	$7,699,030.36	37.0017%
Expense Allocation							
UT1100	CURRENT TAX ALLOCATION ADJUSTMENT - FED	$564,151.01	2.7113%	($2,799,695.44)	0.0000%	($2,235,544.43)	-10.7441%
UT1101	CURRENT TAX ALLOCATION ADJUSTMENT - STATE	$21,289.15	0.1023%	($149,310.80)	0.0000%	($128,021.65)	-0.6153%
UT1102	CURRENT TAX REVERSAL - FED	($564,151.01)	-2.7113%	$2,799,695.43	0.0000%	$2,235,544.42	10.7441%
UT1103	CURRENT TAX REVERSAL - STATE	($21,289.15)	-0.1023%	$149,310.80	0.0000%	$128,021.65	0.6153%
UT1104	DEFERRED TAX ALLOCATION ADJUSTMENT - FED	$5,970,823.70	28.6959%	$4,643,589.45	0.0000%	$10,614,413.15	51.0131%
UT1105	DEFERRED TAX ALLOCATION ADJUSTMENT - STATE	$372,562.06	1.7905%	$147,577.41	0.0000%	$520,139.47	2.4998%
UT1106	DEFERRED TAX REVERSAL - FED	($5,970,823.70)	-28.6959%	($4,643,589.45)	0.0000%	($10,614,413.15)	-51.0131%
UT1107	DEFERRED TAX REVERSAL - STATE	($372,562.06)	-1.7905%	($147,577.41)	0.0000%	($520,139.47)	-2.4998%
Subtotal:		($0.00)	-0.0000%	($0.01)	0.0000%	($0.01)	-0.0000%
ITC Amortization							
UT0910	ITC - FED	($42,802.00)	-0.2057%	$4,627.00	0.0000%	($38,175.00)	-0.1835%
Subtotal:		($42,802.00)	-0.2057%	$4,627.00	0.0000%	($38,175.00)	-0.1835%
Permanent							
UP0120	50% MEALS AND ENTERTAINMENT	$57,614.06	0.2769%	$2,622.55	0.0000%	$60,236.62	0.2895%
UP0130	PENALTIES	$0.00	0.0000%	$14.12	0.0000%	$14.12	0.0001%
UP0170	LOBBYING EXPENSES	$46,639.23	0.2241%	$26,879.62	0.0000%	$73,518.85	0.3533%
UP0210	401K DIVIDEND DEDUCTION	($56,143.21)	-0.2698%	$0.00	0.0000%	($56,143.21)	-0.2698%
UP0216	SISP/SERP PREMIUM & CSV	($266,069.40)	-1.2787%	$464,772.00	0.0000%	$198,702.60	0.9550%
UP0217	PERFORMANCE SHARE PROGRAM-PERM	($221,206.21)	-1.0631%	$150,848.96	0.0000%	($70,357.25)	-0.3381%
UP0310	ROYALTY INCOME - DEDUCTION FOR PERCENTAGE DEPLETION	($584.97)	-0.0028%	$0.00	0.0000%	($584.97)	-0.0028%
Subtotal:		($439,750.49)	-2.1135%	$645,137.25	0.0000%	$205,386.76	0.9871%
Rate Change							
UT1020	1823.2045 - OR TAX RATE CHG - STATE	($23,675.11)	-0.1138%	$0.00	0.0000%	($23,675.11)	-0.1138%
UT1021	2540.20217 - OR TAX RATE CHG - FED	$3,296.30	0.0158%	$0.00	0.0000%	$3,296.30	0.0158%
UT1022	2820.865 - OR TAX RATE CHG - STATE	$38,767.45	0.1863%	$0.00	0.0000%	$38,767.45	0.1863%
UT1023	2820.965 - OR TAX RATE CHG - FED	($10,793.05)	-0.0519%	$0.00	0.0000%	($10,793.05)	-0.0519%
UT1024	2830.865 - OR TAX RATE CHG - STATE	($22,398.65)	-0.1076%	$0.00	0.0000%	($22,398.65)	-0.1076%
UT1025	2830.965 - OR TAX RATE CHG - FED	$6,225.80	0.0299%	$0.00	0.0000%	$6,225.80	0.0299%
Subtotal:		($8,577.26)	-0.0412%	$0.00	0.0000%	($8,577.26)	-0.0412%
Tax Credits & Adjustments							
UT0922	CONSOLIDATING ADJUSTMENT FED	$0.00	0.0000%	($4,553.97)	0.0000%	($4,553.97)	-0.0219%
UT0923	CONSOLIDATING ADJUSTMENT STATE	$0.00	0.0000%	($5,710.94)	0.0000%	($5,710.94)	-0.0274%

Tax Provision Effect Tax Rate Report

00047-Cascade Natural Gas Co.
2017 Actuals CNGC
All Months
ACROSS OPERATING INDICATORS

	Current Period		Adjustments		Total	
	Total Tax	ETR %	Total Tax	ETR %	Total Tax	ETR %
Tax Credits & Adjustments						
UT0930 R&D CREDIT - FED	$0.00	0.0000%	($130,245.00)	0.0000%	($130,245.00)	-0.6260%
Subtotal:	$0.00	0.0000%	($140,509.91)	0.0000%	($140,509.91)	-0.6753%
Expense Booked To/From Other Companies (Discrete)	$0.00	0.0000%	$0.00	0.0000%	$0.00	0.0000%
Total Adjustments to Tax Expense	($640,604.82)	-3.0788%	$1,846,787.60	0.0000%	$1,206,182.78	5.7969%
Tax Expense (Benefit) With Discrete Items	$6,886,023.93	33.0944%	$1,846,787.60	0.0000%	$8,732,811.53	41.9701%
Less: Discrete Items Included Above	$0.00	0.0000%	$0.00	0.0000%	$0.00	0.0000%
Tax Expense (Benefit) Without Discrete Items	$6,886,023.93	33.0944%	$1,846,787.60	0.0000%	$8,732,811.53	41.9701%
Total Tax Expense	$6,886,023.93	33.0944%	$1,846,787.60	0.0000%	$8,732,811.53	41.9701%
Tax Expense Booked	$6,886,023.92		$1,846,787.62		$8,732,811.54	
Difference	$0.01		($0.02)		($0.01)	

CASCADE NATURAL GAS CORPORATION
ALLIANCE OF WESTERN ENERGY CONSUMERS
General Rate Case
UG 347

AWEC DATA REQUEST NO. 13

Date prepared: August 20, 2018

Preparer: Isaac Myhrum

Contact: Pamela Archer

Telephone: (509)-734-4591

Please provide an entity relationship diagram detailing each legal entity owned, controlled or affiliated with MDU Resources Group, Inc., along with corresponding ownership percentages.

Response:

Please see the attached file "AWEC-13 MDU Organizational Ownership Chart.pdf". The entity relationship diagram and ownership percentages are accurate as of August 17, 2018.

- MDU Resources Group, Inc.
  - Centennial Energy Holdings, Inc. (100%)
    - Centennial Energy Resources LLC (100%)
      - Centennial Energy Resources International, In (100%)
        - MDU Resources International LLC (100%)
        - MDU Resources Luxembourg I LLC S.a.r.l. (100%)
          - MDU Resources Luxembourg II LLC S.a.r.l. (100%)
    - Centennial Holdings Capital LLC (100%)
      - FutureSource Capital Corp. (100%)
        - Nevada Solar Solutions, LLC (100%)
      - InterSource Insurance Company (100%)
    - Knife River Corporation (100%)
      - KRC Holdings, Inc. (100%)
        - Alaska Basic Industries, Inc. (100%)
          - Anchorage Sand and Gravel Company, Inc. (100%)
          - Fairbanks Materials, Inc. (100%)
        - Baldwin Contracting Company, Inc. (100%)
          - 1250 Gladding Road, LLC (100%)
        - Concrete, Inc. (100%)
        - Connolly-Pacific Co. (100%)
        - D S S Company (100%)
        - Granite City Ready Mix, Inc. (100%)
        - Jebro Incorporated (100%)
        - JTL Group, Inc. (MT Corporation) (100%)
        - JTL Group, Inc. (Wyoming Corporation) (100%)
        - Kent's Oil Service (100%)
        - Knife River Corporation - Mountain West (100%)
          - Knife River Corporation - North Central (100%)
            - Ames Sand & Gravel, Inc. (100%)
          - Knife River Corporation - Northwest (100%)
            - Central Oregon Redi-Mix, LLC (78%)
        - Knife River Corporation - South (100%)
          - Knife River Dakota, Inc. (100%)
            - Hawaiian Cement (50%)
          - Knife River Hawaii, Inc. (100%)
            - Hawaiian Cement (50%)
        - Knife River Marine, Inc. (100%)
        - Knife River Midwest, LLC (100%)
        - LTM, Incorporated (100%)
        - Northstar Materials, Inc. (100%)
        - WHC, Ltd. (100%)
    - MDU Construction Services Group, Inc. (100%)
      - Bell Electrical Contractors, Inc. (100%)
      - Bombard Electric, LLC (100%)

- Bombard Mechanical, LLC (100%)
- Capital Electric Construction Company, Inc. (100%)
- Capital Electric Line Builders, Inc. (100%)
- Desert Fire Holdings, Inc. (100%)
  - Desert Fire Protection, a Nevada Limited Part (99%)
  - Desert Fire Protection, Inc. (100%)
    - Desert Fire Protection, LLC (100%)
      - Desert Fire Protection, a Nevada Limited Part (1%)
  - Independent Fire Fabricators, LLC (100%)
- International Line Builders, Inc. (100%)
- Lone Mountain Excavation & Utilities, LLC (100%)
- Loy Clark Pipeline Co. (100%)
- MAAK Holdings, Inc. (100%)
- MDU Industrial Services, Inc. (100%)
  - Frebco, Inc. (100%)
  - Wagner Industrial Electric, Inc. (100%)
- MDU United Construction Solutions, Inc. (100%)
  - Duro Electric Company (100%)
  - USI Industrial Services, Inc. (100%)
  - Wagner-Smith Equipment Co. (100%)
- Nevada Valley Solar Solutions I, LLC (100%)
- OEG, Inc. (100%)
- Rocky Mountain Contractors, Inc. (100%)
- Wagner Group, Inc., The (100%)
  - E.S.I., Inc. (100%)
  - Wagner-Smith Company, The (100%)

WBI Holdings, Inc. (100%)
- Fidelity Exploration & Production Company (100%)
  - Fidelity Oil Co. (100%)
- WBI Energy, Inc. (100%)
  - WBI Canadian Pipeline, Ltd. (100%)
  - WBI Energy Midstream, LLC (100%)
  - WBI Energy Transmission, Inc. (100%)
  - WBI Energy Wind Ridge Pipeline, LLC (100%)

Great Plains Natural Gas Co. (100%)

MDU Energy Capital, LLC (100%)
- Prairie Cascade Energy Holdings, LLC (100%)
  - Cascade Natural Gas Corporation (100%)
- Prairie Intermountain Energy Holdings, LLC (100%)
  - Intermountain Gas Company (100%)

MDU Holdings, LLC (100%)

Montana-Dakota Utilities Co. (100%)
- Big Stone-Grant Industrial Development and Tr (22.20%)

CASCADE NATURAL GAS CORPORATION
ALLIANCE OF WESTERN ENERGY CONSUMERS
General Rate Case
UG 347

AWEC DATA REQUEST NO. 15

Date prepared: 8/23/18

Preparer: Kevin Conwell/Aimee Delzer/Dawn Bauer

Contact: Pamela Archer

Telephone: (509)-734-4591

Reference the 2017 Cost Allocation Manual provided in response to Staff data request 164:

a. Please provide workpapers in excel format used to calculate the corporate overhead allocation factor(s) applied in the test period.
b. Please identify the number of employees of MDU Resource Group, Inc. by month over the period 2015 through 2017
c. For each entity owned, controlled or affiliated with MDU Resource Group, Inc., please identify the total number of employees by month over the periods 2015, 2016 and 2017.
d. For each entity owned, controlled or affiliated with MDU Resource Group, Inc., please identify gross revenues in the periods 2015, 2016 and 2017.
e. Please identify the total payroll of MDU Resources Group, Inc. in the periods 2015, 2016, and 2017.
f. For each entity owned, controlled or affiliated with MDU Resource Group, Inc., please identify total payroll expense in the periods 2015, 2016 and 2017.

Response:

(a) See attached files:
AWEC-15 (a) Corporate Overhead Allocation 7.1.17.pdf
AWEC-15 Corporate Overhead 2017.xlsx
(b) See attached file: AWEC-15 (b) &(c) Quarterly Employee Counts_2015_2016_2017.xlsx
(c) See file referenced in (b)
(d) See attached file AWEC-15 (d).xlsx
(e) See attached file AWEC-15 (e) & (f) All company wages 2015-2017.xlsx
(f) See file referenced in part (e)

Montana-Dakota Utilities Co.
CORPORATE OVERHEAD ALLOCATION FACTORS
January-June 2017

09/24/18
10:46 AM

	MONTANA-DAKOTA ELECTRIC	GAS DIST	CNG	IGC	TOTAL UTILITY	WBI	FIDELITY EXPLOR. & PROD.	WBI NON-REGULATED	KRC	CSG	
	.1	.2	.68	.61		.60	.63	.64	.62	.67	
Corporate factor	19.8	13.2	13.6	9.4	56.0	7.4	0.0	5.6	22.3	8.7	100.00
					-						
Montana-Dakota corporate factor	60.1	39.9									100.00
Employee factor	43.9	56.1									100.00
Plant factor	76.2	23.8									100.00
Customer factor	33.0	67.0									100.00

PERCENTAGE BASED ON 9/30/16 CAPITALIZATION

MDU	CNG	IGC	Check	
58.9	24.3	16.8	100.00	Total Utility Group
	59.2	40.8	100.00	MDU EC

Montana-Dakota Utilities Co.
CORPORATE OVERHEAD ALLOCATION FACTORS
July - December 2017

09/24/18
10:46 AM
F:\FINRPT\CORPOVER\2011\[Corporate Overhead.xlsx]Jul-Dec

	.1	.2	.68	.61		.60	.64	.62	.67	
	MONTANA-DAKOTA ELECTRIC	GAS DIST	CNG	IGC	TOTAL UTILITY	WBI	WBI NON-REGULATED	KRC	CSG	
Corporate factor	20.6	13.6	14.1	9.7	58.0	7.7	3.0	22.4	8.9	100.00
					-					
Montana-Dakota corporate factor	60.1	39.9								100.00
Employee factor	43.9	56.1								100.00
Plant factor	76.2	23.8								100.00
Customer factor	33.0	67.0								100.00

PERCENTAGE BASED ON 9/30/16 CAPITALIZATION

MDU	CNG	IGC	Check	
58.9	24.3	16.8	100.00	Total Utility Group
	59.2	40.8	100.00	MDU EC

CASCADE NATURAL GAS CORPORATION
ALLIANCE OF WESTERN ENERGY CONSUMERS
General Rate Case
UG 347

AWEC DATA REQUEST NO. 16

Date prepared: 8/22/2018

Preparer: Kevin Conwell

Contact: Pamela Archer

Telephone: (509)-734-4591

Reference the 2017 Cost Allocation Manual provided in response to Staff data request 164, Page 17, Utility Operations Support, Leadership Group:

a. Please provide workpapers supporting the amount of costs allocated to Cascade under the category Utility Operations Support, Leadership Group:
b. Please identify each leadership individual whose time is allocated under this category.
c. Please identify the total amount of costs allocated to Cascade for Utility Operation Support, Leadership Group by employee.
d. Is the total amount of costs allocated to Cascade for Utility Operations Support Leadership Group in 2017, the same as the amount identified in response to Staff Data Request 103? If no, please explain.
e. Please explain why it is appropriate to allocate the leadership group in equal portions to each utility brand.
f. For each individual considered in this category please provide all time studies that were used to inform the allocation of costs to Cascade.

Response:

a) See attached files:
AWEC-16 2018 SLD Extra Review MDU IT.xlsx
AWEC-16 Business Services Allocation Methodology 2015-2017.docx
AWEC-16 Business Services Allocation 6.9.16.xlsx
AWEC-16 CS Cost Allocation Manual 2017.docx
AWEC-16 CSC Cost Allocations Worksheet 2017.xlsx
AWEC-16 MDU Gas supply Cost Allocation Manual.docx

CASCADE NATURAL GAS CORPORATION
ALLIANCE OF WESTERN ENERGY CONSUMERS
General Rate Case
UG 347

b) Director Fleet & Procurement, Director Gas Supply, EVP Reg Affairs/Customer Service/Admn/EVP Reg/Customer Service, VP Reg Affairs & Customer Service, Director Enterprise Operations Support, Director Customer Service

c) $283,160.83 (Positions included: Dir Business Services, Dir Gas Supply, EVP Reg Affairs Cust Svc & Gas Supply, VP Reg Affairs & Cust Svc, Dir Enterprise Operations Support, Dir Customer Service)

d) No, these costs are not the same as reported in OPUC DR #103. OPUC DR #103 lists out the salary amounts for positions considered Officers of the corporation. The cost allocation manual addresses EVP's and Directors.

e) If there is no rational basis to allocate a directors time then their time would be allocated evenly across all brands of the utility group. When a better rationale exists then that is used to determine the allocation percentages charged to each company. In 2017 there was only 1 position allocated equally to all brands of the utility group.

f) See responses attached for part (a).

CASCADE NATURAL GAS CORPORATION
ALLIANCE OF WESTERN ENERGY CONSUMERS
General Rate Case
UG 347

AWEC DATA REQUEST NO. 17

Date prepared: 8/21/18

Preparer: Mark Chiles/Kevin Conwell

Contact: Pamela Archer

Telephone: (509)734-4591

Reference the 2017 Cost Allocation Manual provided in response to Staff data request 164, Page 17, Utility Operations Support, Customer Services:

a. Please provide workpapers supporting the amount of costs allocated to Cascade under the category Utility Operations Support, Customer Services:
b. Please identify each employee whose time is allocated under this category.
c. Please identify the total amount of costs allocated to Cascade for Utility Operation Support, Customer Service by employee.
d. Please explain how the allocation percentages for Directors and the Management Team were derived.
e. Please explain why a greater portion of the Directors' cost is allocated to Cascade, relative to individuals on the Management team.

Response: Note the Cost Allocation Manual provided in DR #164 did not reflect the changes and updates referred to in this response.

a. See attached excel file **AWEC-17 CSC Allocations Worksheet 2017.xlsx**
b. See attached excel file **AWEC-17 CSC (b) and (c).xlsx** position titles are identified not the employee.
c. See attached excel file **AWEC-17 CSC (b) and (c).xlsx** total costs allocated to CNG and Oregon allocation amount is identified, but is not broken out by employee.
d. Per the CS Cost Allocation Manual 2017, the allocation percentages for Directors and the Management Team were derived using the customer counts for each of our brands. The MDU customers were broken down by gas only customers, electric only customers, and combination customers. The 2017 allocation was based on the average of the monthly customers from December 2015 through

**CASCADE NATURAL GAS CORPORATION
ALLIANCE OF WESTERN ENERGY CONSUMERS
General Rate Case
UG 347**

November 2016. A weighting was applied to the MDU combination customers in order to recognize that theses customers may require additional resources beyond those of a single energy source customer. At the same time, there are significant efficiencies for dual fuel customers that provide time and money savings such as single customer input thus these customers have been weighted at 1.25 times a single source customer. The allocation factors are then a simple percentage of the total for Cascade Natural Gas Corporation and Intermountain Gas Company while the allocations to MDU/GP are allocated by electric and natural gas. See also attached word document **AWEC-17 CS Cost allocation Manual 2017.docx**

e. The percentage of cost allocated to Cascade from the Director position would be the same as the other management positions at 27.90% as detailed in the spreadsheet provided in response to this DR section a.

CASCADE NATURAL GAS CORPORATION
ALLIANCE OF WESTERN ENERGY CONSUMERS
General Rate Case
UG 347

AWEC DATA REQUEST NO. 41

Date prepared: 9/19/18

Preparer: Kevin Conwell

Contact: Pamela Archer

Telephone: (509)-734-4591

Reference Cascade's response to AWEC 15, Attachment AWEC-15: Please provide workpapers supporting the calculation of the hard coded numbers in cells "F14:K14" for both Tabs in the referenced attachment.

Response:

See attached file AWEC-41.pdf.

MDU Resources Group, Inc.
Corporate Overhead Allocation Factors
January 1, 2017

	Montana-Dakota	MDU Energy Capital	WBI Energy & Energy Services Transmission	WBI Energy & Energy Services Midstream	WBI Energy & Energy Services	Knife River	Construction Services	Total
01/01/2017*	32.4%	23.6%	7.4%	5.6%	13.0%	22.3%	8.7%	100.0%
7/1/2016**	30.0%	23.5%	7.3%	7.9%	15.2%	23.0%	8.3%	100.0%
Difference	2.4%	0.1%	0.1%	(2.3%)	(2.2%)	(0.7%)	0.4%	0.0%
Average OH Factor	31.2%	23.5%	7.4%	6.7%	14.1%	22.7%	8.5%	100.0%
Average Capitalization - 12 months ended 09/30/2016	1,309,371,767.04	956,146,914.62	300,108,688.23	226,439,976.53	526,548,664.76	904,269,873.65	350,199,278.90	4,046,536,498.97
Average Capitalization - 12 months ended 03/31/2016	1,215,990,119.02	949,441,630.02	296,359,874.85	319,032,968.88	615,392,843.73	930,604,598.23	334,905,958.33	4,046,335,149.33

56.0

* Based on average capitalization [current and noncurrent debt (including capital lease obligations) and equity] for the 12 months ended September 30, 2016.
** Based on average capitalization [current and noncurrent debt (including capital lease obligations) and equity] for the 12 months ended March 31, 2016.

Vu 11/28/16

DM
11/28/16

CASCADE NATURAL GAS CORPORATION
ALLIANCE OF WESTERN ENERGY CONSUMERS
General Rate Case
UG 347

AWEC DATA REQUEST NO. 42

Date prepared: 9/24/2018

Preparer: Kevin Conwell/Mark Chiles

Contact: Pamela Archer

Telephone: (509)-734-4591

Reference Cascade's response to AWEC 16:

a. Please provide the customer count data used to calculate the percentages in attachment "AWEC-16 CSC Allocations Worksheet 2017"
b. When calculating customer count does Cascade consider a customer who is both a gas and electric customer of Montana Dakota Utilities to be a single customer, or two customers?
c. Please provide workpapers calculating the $283,160.83 amount, detailing the allocation by employee, and including support for the underlying allocation percentages.

Response:

a) See attached file AWEC-42-AWEC-16 CSC Allocations Worksheet 2017.xlsx The tabs have been renamed to "Allocations" and "Customer Counts". Customer counts used in the percentage allocations are included.
b) The company uses an adjustment factor of 1.25x for MDU customers who are both natural gas and electric customers. This factor recognizes the efficiencies provided by serving a combination customer, but also accounts for services provided that are specific to an energy source.
c) See attached file AWEC-42 (c).xlsx for explanations or references to employee labor allocations.

CASCADE NATURAL GAS CORPORATION
ALLIANCE OF WESTERN ENERGY CONSUMERS
General Rate Case
UG 347

AWEC DATA REQUEST NO. 46

Date prepared: 09/13/2018

Preparer: Chris Ryan

Contact: Pamela Archer

Telephone: (509)-734-4591

Reference Cascade's response to AWEC 29, Attachment AWEC-29: Please provide a narrative description of how MDU's payments to "Chad Berger Bucking Bulls" benefits Oregon ratepayers.

Response:

The invoice total is $2,500.00, of which $340.00 is allocated to Cascade, which in turn is allocated to Oregon in the amount of $84.86.

Per AWEC-29: As Cascade is a subsidiary of MDU Resources, these costs benefit all the subsidiaries of the Corporation.

CASCADE NATURAL GAS CORPORATION
ALLIANCE OF WESTERN ENERGY CONSUMERS
General Rate Case
UG 347

AWEC DATA REQUEST NO. 47

Date prepared: 09/13/2018

Preparer: Chris Ryan

Contact: Pamela Archer

Telephone: (509)-734-4591

Reference Cascade's response to AWEC 29, Attachment AWEC-29: Please provide a narrative description of how MDU's payments to "Bareknuckle Baseball LLC" benefits Oregon ratepayers.

Response:

The invoice total is $12,500.00 and $117.15, of which $1,715.93 is allocated to Cascade, which in turn is allocated to Oregon in the amount of $428.30.

Per AWEC-29: As Cascade is a subsidiary of MDU Resources, these costs benefit all the subsidiaries of the Corporation.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

	)
In the Matter of	)
	)
CASCADE NATURAL GAS CORPORATION,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT 104

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

September 27, 2018

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 347

Request No. 134

Date prepared: July 18, 2018

Preparer: Maryalice Peters

Contact: Pamela Archer

Telephone: (509)-734-4591

OPUC DATA REQUEST NO. 134

Consistent with Commission Order 16-109 at page 14, issued in Docket UG 288, please provide the following with respect to each Oregon-allocated and situs project over $150,000, as listed in Exhibit CNGC/305, Peters/1-3:

a. Comprehensive cost-benefit analysis of whether and when investment should be built;
b. Evaluation of range of alternative build dates and the impact on reliability and customer rates;
c. Evidence on the likelihood of disruptions based on historical experience;
d. Evidence on the range of possible reliability incidents;
e. Evidence about projected loads and customers in the area; and
f. Consideration of alternatives, including use of interruptibility or increase demand-side measures to improve reliability and system resiliency.

Response:

See various OPUC-134 fund projects attachments.

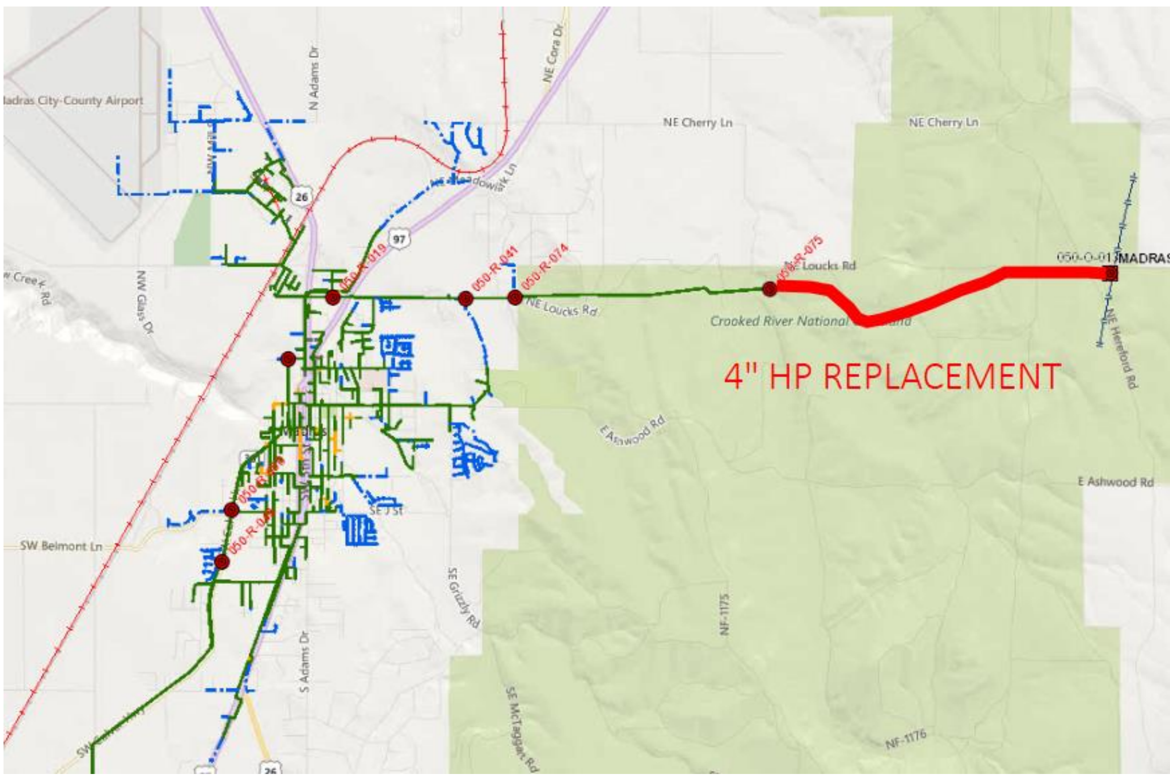
Project Summary – 4" Madras HP Replacement

Submitted by: Chris Bolton
4/23/2018

Background

HP Line 2 in the Bend District starts at the Madras gate and runs into the town of Madras. The pipe that is currently in us is a 4" HP line that was installed in 1962. The MAOP of the line is 260 psi and the line usually operates about 250 psi. This pipeline also has documented leaks and corrosion concerns.

The project site stretches through the Crooked River National Grassland and is shown in the map below:



Proposal

This project consists of installing about 13,000 feet of 6" HP pipeline. Considering the location and the conditions, the majority of the project will be installed via open trench method.

Timing

Design for this project began in May 2017 and plans were completed in January 2018. A contractor pre-bid meeting was held on January 25th, 2018 and five potential bidders attended. The project is scheduled to begin in June 2018 based on the delays in the USFS permit process.

Costs

Engineering has prepared construction plans and bid documents and solicited bids from five bidders. Results from the bid process are summarized below:

BID SUMMARY	
BIDDER	**BID AMOUNT**
Northwest Metal Fab & Pipe, Inc.	$ 1,084,900
Snelson Companies, Inc.	$ 1,079,800
Brothers Pipeline, Inc.	$ 1,036,945
InfraSource	$ 975,771
Michels	$ 730,236

The lower bidder was Michels Construction with $730,236. The overall cost including other factors is shown below:

Category	Cost
Materials	$ 385,000
CNGC labor	$ 26,205
Resources	$ 34,543
Contractors	$ 1,056,264
Overhead	$ 492,580
2017 Design Costs	$ 500,000
Total	**$ 2,494,592**

Benefits

1. Elimination of an aging pipeline with corrosion and leak history.
2. While replacing this line we are also able to gain capacity by upsizing.
3. Replace pre-code pipeline with insufficent construction records.

Alternatives

We have insufficient records on this pipe. Combining this with its old age, replacement is the only reasonable solution.

Responsible People

District Contact: Brian Gainer
Project Engineer: Chris Bolton
Project Foreman: TBD
Cascade Inspector: TBD

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 347

Request No. 164

Date prepared: 7/19/2018

Preparer: Kevin Conwell

Contact: Pamela Archer

Telephone: (509)-734-4591

OPUC DATA REQUEST NO. 164

Please provide the cost allocation manual, guidelines, policies, and training materials for the following entities:

a. MDU Resources Group, Inc.;
b. MDU Energy Capital, LLC;
c. Prairie Cascade Energy Holdings, LLC;
d. Cascade Natural Gas Corporation;
e. CGC Resources, Inc; and
f. All other Cascade Natural Gas affiliates.

Response: See file OPUC-164 CNG Cost Allocation Manual.pdf

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

	)
In the Matter of	)
	)
CASCADE NATURAL GAS CORPORATION,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT 105

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

September 27, 2018

Cascade Natural Gas

Cost Allocation Manual

2017

CASCADE NATURAL GAS CORPORATION

A Subsidiary of MDU Resources Group, Inc.

In the Community to Serve®

Cost Allocation Manual

Table of Contents

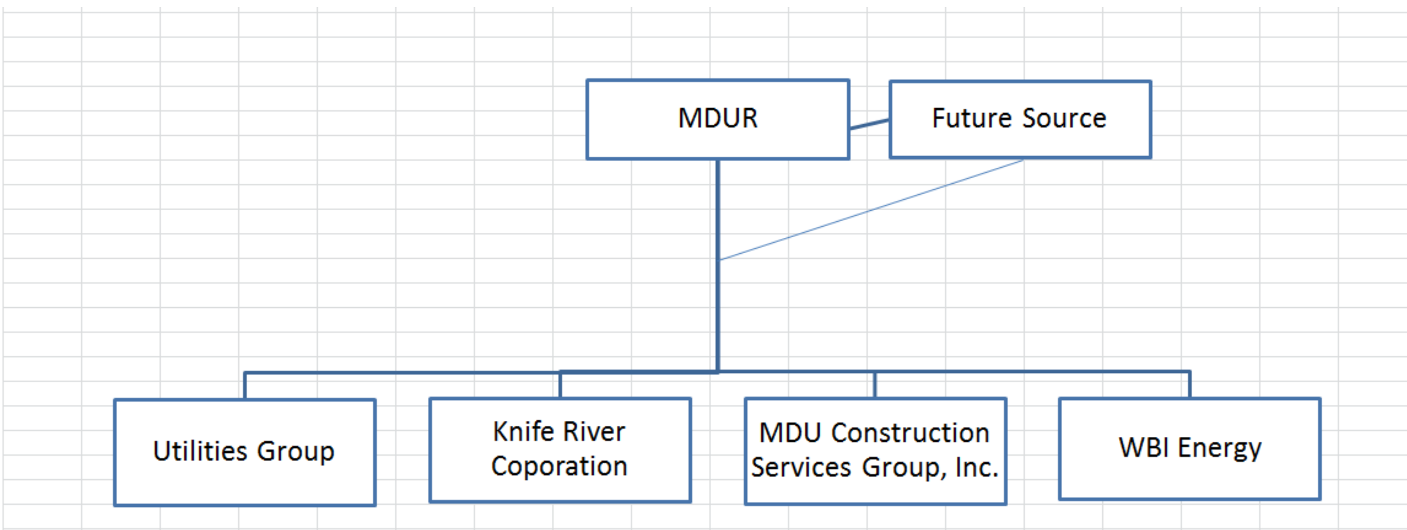
Cost Allocation Manual

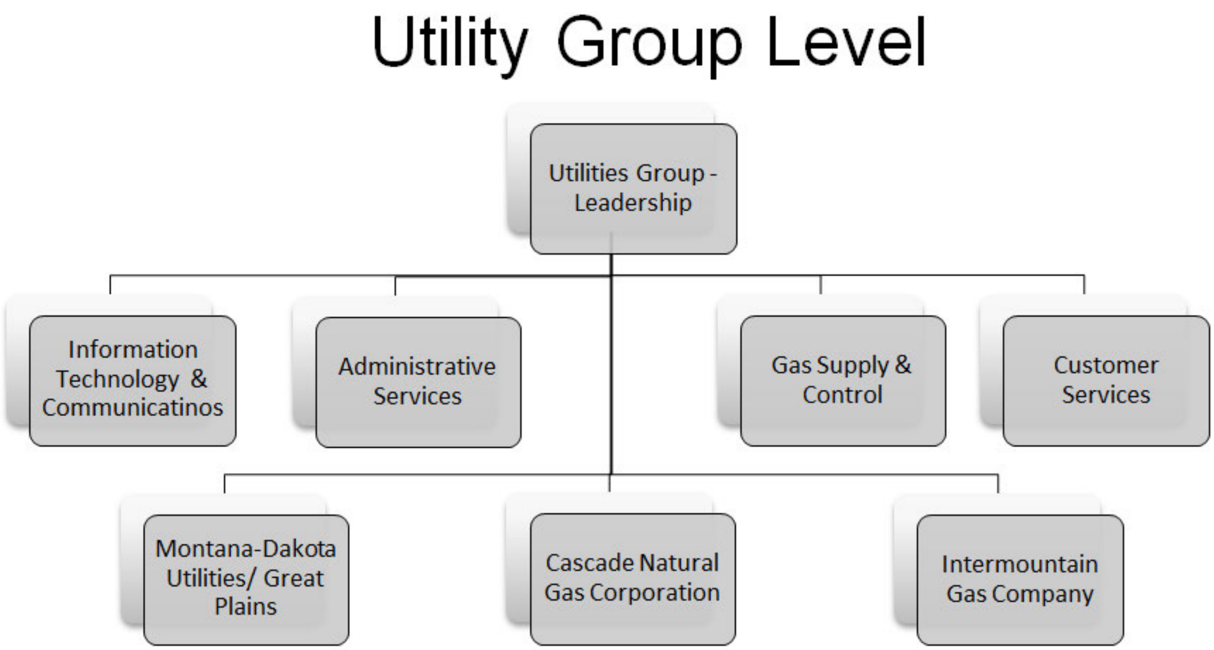
Overview

Cascade Natural Gas Corporation (Cascade), a subsidiary of MDU Resources Group, Inc. (MDUR), conducts business in two states with regulated gas distribution operations.

Below is an overview of the operational structure for the purpose of assigning costs. The diagrams presented are intended to provide an overview for cost allocation only and are 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.)

Corporate Level





This document is intended to provide an overview of the different types of allocations and the processes employed to direct costs to the proper utility and state jurisdiction for Cascade.

This document will discuss the allocations from:

- MDUR and FutureSource to Cascade Natural Gas
- Montana-Dakota/Great Plains (MDU) and Intermountain Gas Company (IGC) to Cascade Natural Gas
- Cascade to MDU and IGC
- 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, procurement and enterprise 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 III)
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 Cascade, the payroll shared services department is also responsible for the accumulation of time entry records and maintenance of employee records. Cascade does not have any departments that provide these payroll related services.

Procurement Shared Services

Procurement Shared Services 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 of the Corporation's operating companies. National accounts, or preferred vendor agreements, typically are negotiated at the corporate level rather than at the local company level. Procurement Shared Services also is responsible for monitoring the level of services, quantities, discounts and rebates associated with established national accounts. Cascade has a single procurement department that places specific purchase requests for materials and services required to conduct business with approved vendors.

Enterprise Technology Service

Enterprise Technology Services (ETS) provides policy guidance, infrastructure related IT functions and security-focused governance. ETS seeks to increase the return on investment in technology through consolidation of common IT systems and services, while eliminating waste and duplication. ETS 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.

Cascade's IT department consists of Montana-Dakota/Great Plains employees physically located in Kennewick, Washington, Boise, Idaho, and Bismarck, North Dakota. This Department is responsible for supporting applications specific to the utility group such as the Customer Care & Billing System, the JD Edwards financial software, Scada and mobile applications, Enterprise GIS, and PowerPlan which is the project and fixed asset accounting software. In addition the utility group IT department develops business continuity plans in the case of disaster recovery.

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
- Travel
- Treasury services

Cascade receives an allocation of these corporate costs. Corporate Policy No. 50.9 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. 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 is reflected as CNGC 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.

The corporate costs allocated to Cascade are subsequently allocated to the state jurisdictions. Corporate costs are recorded in the administrative and general (A&G) function for Cascade. (See state jurisdictional allocation discussion on page 8.)

Montana-Dakota/Great Plains 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. The costs are allocated based on the number of customers served by each utility.

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

Certain Cascade owned assets, such as the portion of the General Office facility used for Shared Services (i.e. Gas Control, IT), located at the utility headquarters in Kennewick, 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 MDU and IGC, as a monthly fee. The costs are allocated based on the number of customers served by each utility.

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)
- Information Technology and Communications- (Management Information Systems, Technology and Compliance)
- Administrative Services - (Procurement, Office Services, Fleet Operations)
- Gas Supply & Control

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 IV.

Standard Labor Distributions

Labor/Reimbursable expense allocations

The development of standard labor distributions for Cascade 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 jurisdiction where possible. If the expense is not direct, the appropriate jurisdiction is charged as follows:

Union Employees

Time tickets are required for productive time. The employee specifies the proper 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.

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 based on an expected ratio of work. 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 periodically.

Cascade Allocations to State Jurisdictions

Cascade 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. The allocation process creates a Journal Entry to the JD Edwards jurisdictional ledgers established by state.

The allocation methodology is as follows:

The JD Edwards (JDE) software is used by Cascade 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:

<u>Business Unit</u> - 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 (i.e. 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 (2 represents gas) 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. It is the combination of the business unit, 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), 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) 47041 represents the geographic location of the Bend, Oregon District. The Bend District is therefore directly assigned to Oregon for all FERC accounts.

Another example is location 4767000, representing the Credit and Collections Department. The allocation of costs is based on the FERC range of accounts. The location may also be a responsibility, or department. An allocation code is used to split the costs between the states. The most common allocation factor is the 3-factor formula (customer, employee and plant). However, the customer ratio, employee ratio, gross plant ratio, and rate base ratio are also used. See Exhibit II for the allocation factor calculations.

*Co	*Location	*Obj Acct	*FERC Sub 1	*FERC Sub 2	*Start Date	Stop Date	Description	Utility Alloc Code	Utility 01	Allocation Code 01
00047	47041		2870	29359999	200601	203512	Central OR District	00002	2	00038
00047	47041		4261	42659999	201208	203512	Bend District-BTL	00002	2	00038
00047	47041	4081	0	99999999	200601	203512	Central OR District-4081	00002	2	00038
00047	47041	5981	4261	4261	200902	201207	Central OR District	00002	2	00038
00047	47041	5984	4263	4263	201111	201207	OR 5984	00002	2	00038

Code 00038 = 100% allocated to Oregon

*Co	*Location	*Obj Acct	*FERC Sub 1	*FERC Sub 2	*Start Date	Stop Date	Description	Utility Alloc Code	Utility 01	Allocation Code 01
00047	4767000		0000	99999	201101	203512	Customer Service Allocated C...	00002	2	00100
00047	4767000	5211	4264	4264	201101	203512	Labor Rel & Comp	00002	2	00100
00047	4767000	5984	4263	4263	201108	203512	Corporate 5984	00002	2	00100

*Co	*Location	*Obj Acct	*FERC Sub 1	*FERC Sub 2	*Start Date	Stop Date	Description	Utility Alloc Code	Utility 01	Allocation Code 01
00047	47042		2870	29359999	200601	203512	Pendleton District	00002	2	00038
00047	47042		4261	42659999	200601	203512	Pendleton District-BTL	00002	2	00038
00047	47042	4081	0	9999999	200601	203512	Pendleton District-4081	00002	2	00038

Allocation Code 01 Represents the code used to allocate to a Jurisdiction
00038 = Oregon
00048 = Washington
00100 = 3 Factor Formula (customer, employee, plant)
00101 = Customer Ratio
00102 = Employee Ratio
00103 = Gross Plant Ratio

Co	Juris Alloc Code	Juris Start Date	Juris Stop Date	Description 10	State 01	Percent 01	State 02	Percent 02
00047	00100	201501	201512	3 Factor formula -(customer, employee, plant)	OR	24.270000	WA	75.730000
00047	00101	201501	201512	Customer Ratio	OR	24.940000	WA	75.060000
00047	00102	201501	201512	Employee Ratio	OR	25.440000	WA	74.560000
00047	00103	201501	201512	Gross Plant Ratio	OR	22.420000	WA	77.580000
00047	00104	201501	201512	Rate Base Ratio	OR	23.540000	WA	76.460000

Exhibit I- MDUR Corporate Overhead factor

MDU Resources Group Inc.
Corp Overhead Alloc Factors Jan-Jun 2017

	MONTANA-DAKOTA ELECTRIC	MONTANA-DAKOTA GAS DIST	CNG	IGC	TOTAL UTILITY	WBI	FIDELITY EXPLOR. & PROD.	WBI NON-REGULATED	KRC	CSG	
Corporate factor	19.8	13.2	13.6	9.4	56.0	7.4	0.0	5.6	22.3	8.7	100.00

Average Capitalization - 12 months ended 09/30/2015 for Corporate Overhead Factors Effective January 1, 2016

	Utility Group	WBI Energy	Knife River	Construction Services	Total
Debt and Equity					
Short-term borrowings	---	6,583,333.33	---	---	6,583,333.33
LTD due within one year	51,215,181.58	43,416,666.66	75,482,018.10	35,014,109.04	205,127,975.38
Long-term debt	944,553,238.29	265,383,037.36	295,332,700.51	75,297,579.08	1,580,566,555.24
Total Debt	**995,768,419.87**	**315,383,037.35**	**370,814,718.61**	**110,311,688.12**	**1,792,277,863.95**
Stockholders' equity:					
Preferred stocks	15,000,000.00				15,000,000.00
Common stock	195,212,981.75		800,000.00	1,000.00	196,013,981.75
Other paid-in capital	1,654,872,956.62		489,889,551.81	134,623,649.93	2,279,386,158.36
Retained earnings	1,492,116,748.63		122,708,512.63	93,237,371.98	1,708,062,633.24
Accumulated other comprehensive loss	(40,262,509.76)		(23,497,919.69)	(2,496,243.34)	(66,256,672.79)
Treasury stock	(3,625,812.59)		(3,625,812.59)	---	(7,251,625.18)
Equity at WBI - Equity components provided in total	---	316,551,619.60	---	---	316,551,619.60
Total common stockholders' equity	**3,298,314,364.65**	**316,551,619.60**	**586,274,332.16**	**225,365,778.57**	**4,426,506,094.98**
Total stockholders' equity	**3,313,314,364.65**	**316,551,619.60**	**586,274,332.16**	**225,365,778.57**	**4,441,506,094.98**
Total liabilities and stockholders' equity	**4,309,082,784.52**	**631,934,656.95**	**957,089,050.77**	**335,677,466.69**	**6,233,783,958.93**
IC investment in subsidiaries	2,280,176,898.63	---	---	---	2,280,176,898.63
Capitalization	**2,028,905,885.89**	**631,934,656.95**	**957,089,050.77**	**335,677,466.69**	**3,953,607,060.30**
	51.3%	16.0%	24.2%	8.5%	100.0%

	9/30/2016 Capitalization	Share of Corp. Allocation	Corporate Allocation
Montana-Dakota	**1,366,017**	**58.9%**	**33.0%**
Cascade	**565,055**	**24.3%**	**13.6%**
Intermountain	**389,942**	**16.8%**	**9.4%**
Total Utilities Group	**2,321,014**	**100.0%**	**56.0%**

Exhibit II- Cascade Allocation Factors

Cascade Natural Gas Corportation
CY 2016 Allocation Factors

Cascade Natural Gas Corporation
State Allocation Formulas
2016

	Washington	Oregon	Total
Customers	74.68%	25.32%	100.00%
Employees	72.99%	27.01%	100.00%
Gross Plant	77.45%	22.55%	100.00%
3-Factor Formula	75.04%	24.96%	100.00%
Rate Base Ratio	77.16%	22.84%	100.00%

Cascade Natural Gas Corporation
Average No. of Employees
2016

Source: Customers Per Employee report

	Mo-Yr	Washington District Employees (1)	Oregon District Employees (1)	
	Dec-15	171	62	
	Jan-16	171	62	
	Feb-16	175	66	
	Mar-16	180	65	
	Apr-16	180	66	
	May-16	181	65	
	Jun-16	182	64	
	Jul-16	191	71	
	Aug-16	191	72	
	Sep-16	190	73	
	Oct-16	189	73	
	Nov-16	185	70	
	Dec-16	186	67	
		2,372	876	
Average of Monthly Averages		183	68	250
	Percentage	72.99%	27.01%	100.00%

(1) Excludes Interstate employees

Cascade Natural Gas Corporation
Gross Plant Percentage
2016

	Washington Incl. CCNC	Oregon Incl. CCNC	Total
Avg. of Mo. Avg.s	677,494,189	197,221,697	874,715,886
Percentage	77.45%	22.55%	100.00%

Cascade Natural Gas Corporation
Average Number of Customers
2016

	Average No. of Customers	Percentage
Washington	207,869	74.68%
Oregon	70,484	25.32%
Total	278,353	100.00%

Cascade Natural Gas Corporation
Rate Base Ratio
2016

The following percentages are used for allocating interest on debt:

	2016 Average Rate Base	Plant Formula
Washington	266,545,413	77.16%
Oregon	78,897,061	22.84%
	345,442,474	100.00%

Exhibit III- MDUR Shared Services Pricing Methodology

MDU Resources Shared Services

Pricing Methodology - Effective for 2017

Note: MDU Resources' use of Shared Services – MDU Resources costs for each shared services function is charged based 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

$ 0.50 per check for the next 500 checks

$ 0.25 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

$ 0.50 per check for the next 500 checks

$ 0.25 per check for each additional check

Additionally, there will be a $4.65 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.

762 –Procurement Shared Services:

Procurement Shared Services costs are invoiced based on five separate factors, all carrying an equal weight of 20%. The factors are:

- Number of Visa Cards as of 8/1/16
- Total Visa Spend for 2015
- National Account Spend for 2015
- Number of Construction Equipment Acquisitions in 2015
- Number of Fleet Acquisitions in 2015

	MDUR	MDU	WBIE	KRC	CSG	CNG	IGC	Total
# VISA cards	187	1,173	558	1,518	1,288	446	157	5,327
% of VISA cards	3.51%	22.02%	10.47%	28.50%	24.18%	8.37%	2.95%	100%
VISA spend	1,581,487	7,131,765	3,873,021	12,438,266	8,886,906	2,634,527	1,280,514	37,826,486
% of Total VISA spend	4.18%	18.86%	10.24%	32.88%	23.49%	6.96%	3.39%	100%
National Account Spend	1.891,207	17,506,783	8,234,912	95,811,922	28,575,267	7,336,137	4,365,242	163,721,470
% of National Account Spend	1.16%	10.69%	5.03%	58.52%	17.45%	4.48%	2.67%	100%
	MDUR	**MDU**	**WBIE**	**KRC**	**CSG**	**CNG**	**IGC**	**Total**
# Construction Equip	0	53	11	78	34	23	7	206

Acquisitions								
% of Construction Equip Acquisitions	0.00%	25.73%	5.34%	37.86%	16.50%	11.17%	3.40%	100%
# Fleet Acquisitions	0	70	27	189	146	33	31	496
% of Fleet Acquisitions	0.00%	14.12%	5.44%	38.10%	29.44%	6.65%	6.25%	100%
Total weighted allocation factor	1.77%	18.28%	7.31%	39.17%	22.21%	7.53%	3.73%	100.00%

766 –Time Entry Shared Services:

Service provided 100% to the MDU Utility Group.

Enterprise Technology Services (ETS):

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

Application Services (765) 100% of these costs are based on the corporate factor.

Customer Relations (965) – The enterprise costs associated with customer relations are invoiced based upon the number of devices supported by customer relations. The metric used to determine device counts is devices that have checked into active directory during a 60 day period in the summer of 2016.

	MDUR	MDU	WBIE	KRC	CSG	CNG	IGC	Total
Device Counts	284	1,181	406	2,007	1,525	469	656	6,528
% of Device Counts	4.35%	18.10%	6.22%	30.74%	23.36%	7.18%	10.05%	100%
Totals	4.35%	18.10%	6.22%	30.74%	23.36%	7.18%	10.05%	100%

Communications & Security (971)

Cost Allocation Manual

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

1. Wide Area Network/Local Area Network/Metropolitan Area Network- Number of business unit locations (40%)

2. Internet/Firewall Access – Number of user accounts (40%)

3. Security (20%)

The costs are invoiced based on the following percentages:

	MDUR	MDU	WBIE	KRC	CSG	CNG	IGC	Total
WAN/LAN/MAN	3	55	131	203	59	18	13	482
% of Business Unit Locations	0.62%	11.41%	27.18%	42.12%	12.24%	3.73%	2.70%	100%
Internet Access/Firewall	284	1,181	406	2,007	1,525	469	656	6,528
% of User Accounts	4.35%	18.10%	6.22%	30.74%	23.36%	7.18%	10.05%	100%
Voice	225	571	311	1,435	68	318	308	3,236
% of Handsets	6.95%	17.65%	9.61%	44.34%	2.10%	9.83%	9.52%	100%
Totals	3.38%	15.34%	15.28%	38.01%	14.66%	6.33%	7.00%	100.00%

Operations (972) – Enterprise charges for the operations group are invoiced using two separate factors. 95.9% of the costs are based upon the number of servers that are supported for a particular business unit. These servers are then broken out between full service servers and shared service servers. 4.1% of the costs are for costs specific to the AS/400 are invoiced upon the AS/400 allocation as agreed to by MDU and WBI.

The costs that are based upon the number of servers are based on the following percentages:

1. Full Service Servers- (61.49%)

2. Shared Service Servers – (38.51%)

	MDUR	MDU	WBIE	KRC	CSG	CNG	IGC	Total
Full Service Servers	305	152	35	103	31	0	0	626
% of Full Service Servers	48.72%	24.29%	5.59%	16.45%	4.95%	0.00%	0.00%	100%
Shared Service Servers	18	97	39	52	73	34	79	392
% of Full Service Servers	4.59%	24.75%	9.95%	13.27%	18.62%	8.67%	20.15%	100%
Totals	31.73%	24.45%	7.27%	15.23%	10.22%	3.34%	7.76%	100%

Finance and Administration (982) –. Costs for the finance and administration group are invoiced based upon the combined methodologies of the four previously identified ETS groups.

	MDUR	MDU	WBIE	KRC	CSG	CNG	IGC	Total
% of Total Finance & Administration	18.40%	17.93%	9.50%	26.05%	15.10%	5.34%	7.68%	100%

Exhibit IV- Utility Operations Support Allocation Methodology

Utility Operations Support
Labor Distribution Allocation Methodology

Leadership Group:

- Includes Executive Vice Presidents & Directors
- Oversees all shared, utility specific functions in the following areas:
  - Customer Services
  - Administrative Services
  - Information Technology & Communications
  - Engineering and Operations Procedures
  - Gas Supply and Gas Control
- Allocation methodology:
  - Equal portion allocated to each utility company, or brand
  - For portion allocated to Montana-Dakota/Great Plains, if there is involvement with non-utility work allocate 1% (including 0.25% for Great Plains) to non-utility based on historical estimates, with remainder allocated to gas and electric based on meter count.
  - For portion allocated to Montana-Dakota/Great Plains, if there is no involvement with non-utility work, allocate between gas and electric based on meter count.

Customer Services:

- Director
  - 35% to CNG, 30% to IGC, 35% Montana-Dakota/Great Plains [1] (1% to non-utility) and remainder split between gas and electric meter count.
- Management team
  - Supervisors: Front line supervision for Customer Service Center
    - 30% to CNG, 30% to IGC, 40% Montana-Dakota/Great Plains [1] (2% to non-utility) and remainder allocated to gas and electric based on the estimate of time required to supervise
  - Manager: Customer service
    - 30% CNG, 20% IGC, 50% Montana-Dakota/Great Plains [1] (2% to non –utility) and remainder allocated to gas and electric meter count.
- Credit
  - Responsible for credit and collections for the Utility Group
  - Allocation Methodology
    - Most agents only handle credit activity for one brand, they charge all time to that brand
    - For agents that handle multiple brands, time is charged based on how much time is spent on each brand

____

[1] Based on estimated time using history

- For agents that only handle credit activity for Montana-Dakota/Great Plains:
  - Allocated to gas and electric based on meter count

  For agents that handle credit for Montana-Dakota/Great Plains and another brand, the portion is allocated to each utility based on average time spent in each utility with the Montana-Dakota/Great Plains portion allocated to gas and electric based on meter count.

- Scheduling
  - Responsible for scheduling field work for employees performing work in the field for the Utility Group
  - Responsible for emergency response 24/7
  - Allocation Methodology:
  - Management team:
    - Manager 20% IGC, 30% CNG, 50% Montana-Dakota/Great Plains[1] allocated to gas and electric based on meter count.
    - Team Leads 25% IGC, 25% CNG, 50% Montana-Dakota/Great Plains[1] allocated to gas and electric based on meter count.
    - For employees that only schedule one brand, charge time to that brand
    - For employees that schedule both IGC and CNG, split time 50/50 based on estimated time required
    - For employees who schedule all brands, split evenly
    - For employees that only schedule Montana-Dakota/Great Plains:
      - Allocated between gas and electric based on meter count
    - For employees that schedule credit for Montana-Dakota/Great Plains and another brand, the portion is allocated to each utility based on the shared utility. The Montana-Dakota/Great Plains allocation is based on the gas and electric meter count.

- Customer Service
  - Responsible for handling all inbound calls during regular operating hours
  - Allocation Methodology:
    - Teams leads and Customer Care Representatives (CCR's) when only responsible for one brand, charge all that time to one brand
    - For employees covering multiple brands, estimates are routinely made for allocations for the pay period
    - For employees responsible for Montana-Dakota/Great Plains:
      - 3% (including 0.5% for Great Plains) is charged to non-utility for credit activity associated with non-utility charges, based on best estimate of time required
      - Remainder is allocated between gas and electric based on meter count

- For employees responsible for Montana-Dakota/Great Plains and another brand, the portion allocated to non-utility is reduced accordingly to 3% (including 0.5% for Great Plains) of the total associated with Montana-Dakota/Great Plains.

- Customer Programs & Support
  - Responsible for inbound self-service, web help, customer program transactions, and analytical support for the Utility Group
  - Allocation Methodology:
  - Manager
    - 30% IGC, 30% CNG, 40% Montana-Dakota/Great Plains[1] (allocate to gas and electric based on meter count)
      - Based on additional time for Montana-Dakota/Great Plains on social media updates & Credit Dept. responsibilities
  - Supervisor, Team Lead, and Support Staff
    - Equal portion allocated to each brand
    - For portion allocated to Montana-Dakota/Great Plains, if there is involvement with non-utility work allocate 1% (including 0.25% for GPNG) to non-utility, based on historical estimates, with remainder allocated to gas and electric based on meter count.
    - For portion allocated to Montana-Dakota/Great Plains, if there is no involvement with non-utility work, allocated to gas and electric based on meter count.

- Note: Exceptions may be made on an individual basis from these guidelines
  - Employees may be assigned special projects, and allocation methodology may be changed accordingly.
  - Labor allocation may always be made on an actual time spent basis rather than these guidelines.
  - Supervisors may alter these guidelines based on their individual scenario.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

	)
In the Matter of	)
	)
CASCADE NATURAL GAS CORPORATION,	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT 106

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

September 27, 2018

Potential Overhead Cost Allocators

Line	Description	Knife River	WBI Resources	Construction Services	Montana Dakota Utilities	Intermountain Natural Gas	Cascade Natural Gas	Hold Co MDU Resources	Total
1	**Capital Factors**								
2	A1.Book Capital (as proposed by Cascade)								
3	1/1/2017 - 6/30/2017	22.30%	13.00%	8.70%	33.00%	9.40%	13.60%	0.00%	100%
4	7/1/2017 - 12/31/2017	22.40%	13.00%	8.90%	34.20%	9.70%	14.10%	0.00%	102%
5	Factor %	22.35%	13.00%	8.80%	33.60%	9.55%	13.85%	0.00%	101%
6	**% after Hold Co Share**	**22.35%**	**13.00%**	**8.80%**	**33.60%**	**9.55%**	**13.85%**	**0.00%**	
7	Oregon %						24.96%		
8	*Oregon Factor*						*3.46%*		
9	A2 . Capital (using rate base in place of book balue)								
10	Per AWEC DR 40	930,604,598	615,392,844	334,905,958	1,309,371,767	575,331,110		-	3,765,606,277
11	Cascade OR Rate Base						93,383,892		93,383,892
12	Cascade WA Rate Base (per UE-170929 Stipulation)						280,726,628		280,726,628
13	Total	930,604,598	615,392,844	334,905,958	1,309,371,767	575,331,110	374,110,520	-	4,139,716,797
14	Factor %	22.48%	14.87%	8.09%	31.63%	13.90%	9.04%	0.00%	
15	**% after Hold Co Share**	**16.86%**	**11.15%**	**6.07%**	**23.72%**	**10.42%**	**6.78%**	**25.00%**	**100%**
16	Oregon %						24.96%		
17	*Oregon Factor*						*1.69%*		
18	**Labor Factors**								
19	B1. Wages	319,895,335	29,762,060	14,704,233	87,673,940	19,627,537	29,684,120	16,954,329	518,301,555
20	Factor %	61.72%	5.74%	2.84%	16.92%	3.79%	5.73%	3.27%	100%
21	**% after Hold Co Share**	**47.86%**	**4.45%**	**2.20%**	**13.12%**	**2.94%**	**4.44%**	**25.00%**	**100%**
22	Oregon %						24.96%		
23	*Oregon Factor*						*1.11%*		
24	B2. Employee Count (2017 Average)	4356	337.75	5169	1053	239	347.5	157	11659.25
25	Factor %	37.36%	2.90%	44.33%	9.03%	2.05%	2.98%	1.35%	100%
26	**% after Hold Co Share**	**28.40%**	**2.20%**	**33.70%**	**6.87%**	**1.56%**	**2.27%**	**25.00%**	**100%**
27	Oregon %						24.96%		
28	*Oregon Factor*						*0.57%*		
29	**Gross Revenue Factors**								
30	C. Gross Revenues	1,812,529,404	122,212,892	1,367,601,528	623,692,864	277,041,186	290,459,640	-	4,493,537,514
31	Factor%	40.34%	2.72%	30.43%	13.88%	6.17%	6.46%	0.00%	100%
32	**% after Hold Co Share**	**30.25%**	**2.04%**	**22.83%**	**10.41%**	**4.62%**	**4.85%**	**25.00%**	**100%**
33	Oregon %						24.96%		
34	*Oregon Factor*						*1.21%*		
35	**Proposed 4-factor (Factors A2, B1, B2& C)**								
36	**Average A2, B1, B2 & C**	**30.84%**	**4.96%**	**16.20%**	**13.53%**	**4.89%**	**4.58%**	**25.00%**	
37	Oregon %						24.96%		
38	Oregon Factor						*1.14%*		

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

In the Matter of	)
	)
CASCADE NATURAL GAS CORPORATION,	)
	)
Request for a General Rate Revision.	)

EXHIBIT 107

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

September 27, 2018

Carryovers to Next Year

	Regular Tax	Alternative Minimum Tax
Non-SRLY NOL	292,661,992.	252,407,466.
Charitable contributions	4,884,761.	4,803,914.
Capital loss carryovers	394,349.	
Total general business credits	7,224,770.	
Credit for increasing research activities (Form 6765)	159,167.	
Renewable electricity production credit (Form 8835, Part I)	7,065,603.	
Work opportunity credit (Form 5884, Part II)	7,011.	
Renewable electricity production credit (Form 8835, Part II)	9,843,070.	
Minimum tax credit (Form 8827)	25,210,981.	

AWEC/107
Mullins/2

Form **1120** Department of the Treasury Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2016 or tax year beginning ____________, ending ____________

▶ Information about Form 1120 and its separate instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

A Check if:
1a Consolidated return (attach Form 851) X
b Life/nonlife consolidated return
2 Personal holding co. (attach Sch. PH)
3 Personal service corp. (see instructions)
4 Schedule M-3 attached X

TYPE OR PRINT

Name MDU RESOURCES GROUP INC. AND SUBSIDIARIES

Number, street, and room or suite no. If a P.O. box, see instructions.
P O BOX 5650

City or town, state, or province, country, and ZIP or foreign postal code
BISMARCK, ND 58506-5650

B Employer identification number 41-0423660

C Date incorporated 03/14/1924

D Total assets (see instructions) $ 6,284,467,122.

E Check if: (1) Initial return (2) Final return (3) Name change (4) Address change

Income	1a Gross receipts or sales	1a	4,509,061,263.	
	b Returns and allowances	1b	12,447.	
	c Balance. Subtract line 1b from line 1a		1c	4,509,048,816.
	2 Cost of goods sold (attach Form 1125-A)		2	3,586,923,685.
	3 Gross profit. Subtract line 2 from line 1c		3	922,125,131.
	4 Dividends (Schedule C, line 19)		4	2,392.
	5 Interest		5	22,054,798.
	6 Gross rents		6	3,403,056.
	7 Gross royalties		7	
	8 Capital gain net income (attach Schedule D (Form 1120))		8	NONE
	9 Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)		9	-189,306,309.
	10 Other income (see instructions - attach statement)		10	69,612,959.
	11 **Total income.** Add lines 3 through 10 ▶		11	827,892,027.
Deductions (See instructions for limitations on deductions.)	12 Compensation of officers (see instructions - attach Form 1125-E) ▶		12	31,871,787.
	13 Salaries and wages (less employment credits)		13	89,933,496.
	14 Repairs and maintenance		14	15,647,650.
	15 Bad debts		15	5,705,164.
	16 Rents		16	30,374,903.
	17 Taxes and licenses		17	89,490,186.
	18 Interest		18	104,487,008.
	19 Charitable contributions		19	NONE
	20 Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)		20	253,445,477.
	21 Depletion		21	9,729,177.
	22 Advertising		22	2,394,949.
	23 Pension, profit-sharing, etc., plans		23	1,884,856.
	24 Employee benefit programs		24	10,362,736.
	25 Domestic production activities deduction (attach Form 8903)		25	
	26 Other deductions (attach statement)		26	202,417,688.
	27 **Total deductions.** Add lines 12 through 26 ▶		27	847,745,077.
	28 Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11		28	-19,853,050.
	29a Net operating loss deduction (see instructions)	29a		
	b Special deductions (Schedule C, line 20)	29b	181,675.	
	c Add lines 29a and 29b		29c	181,675.
Tax, Refundable Credits, and Payments	30 **Taxable income.** Subtract line 29c from line 28. See instructions		30	-20,034,725.
	31 Total tax (Schedule J, Part I, line 11)		31	
	32 Total payments and refundable credits (Schedule J, Part II, line 21)		32	115,751.
	33 Estimated tax penalty. See instructions. Check if Form 2220 is attached ▶		33	
	34 **Amount owed.** If line 32 is smaller than the total of lines 31 and 33, enter amount owed		34	
	35 **Overpayment.** If line 32 is larger than the total of lines 31 and 33, enter amount overpaid		35	115,751.
	36 Enter amount from line 35 you want: **Credited to 2017 estimated tax** ▶ Refunded ▶		36	115,751.

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Signature of officer JASON VOLLMER | Date 08/30/2017 | Title VP, CAO, & TREASURER

May the IRS discuss this return with the preparer shown below? See instructions. Yes No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check if self-employed	PTIN

Firm's name ▶ | Firm's EIN ▶
Firm's address ▶ | Phone no.

For Paperwork Reduction Act Notice, see separate instructions. Form **1120** (2016)

JSA
6C1110 2.000

41-0423660

Schedule C Dividends and Special Deductions (see instructions)	(a) Dividends received	(b) %	(c) Special deductions (a) x (b)
1 Dividends from less-than-20%-owned domestic corporations (other than debt-financed stock)	2,392.	70	1,674.
2 Dividends from 20%-or-more-owned domestic corporations (other than debt-financed stock)		80	
3 Dividends on debt-financed stock of domestic and foreign corporations		see instructions	
4 Dividends on certain preferred stock of less-than-20%-owned public utilities		42	
5 Dividends on certain preferred stock of 20%-or-more-owned public utilities		48	
6 Dividends from less-than-20%-owned foreign corporations and certain FSCs		70	
7 Dividends from 20%-or-more-owned foreign corporations and certain FSCs		80	
8 Dividends from wholly owned foreign subsidiaries		100	
9 **Total.** Add lines 1 through 8. See instructions for limitation			1,674.
10 Dividends from domestic corporations received by a small business investment company operating under the Small Business Investment Act of 1958		100	
11 Dividends from affiliated group members		100	
12 Dividends from certain FSCs		100	
13 Dividends from foreign corporations not included on line 3, 6, 7, 8, 11, or 12			
14 Income from controlled foreign corporations under subpart F (attach Form(s) 5471)			
15 Foreign dividend gross-up			
16 IC-DISC and former DISC dividends not included on line 1, 2, or 3			
17 Other dividends			
18 Deduction for dividends paid on certain preferred stock of public utilities			180,001.
19 **Total dividends.** Add lines 1 through 17. Enter here and on page 1, line 4 ▶	2,392.		
20 **Total special deductions.** Add lines 9, 10, 11, 12, and 18. Enter here and on page 1, line 29b ▶			181,675.

Schedule J Tax Computation and Payment (see instructions)

Part I-Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)). See instructions ▶ X				
2	Income tax. Check if a qualified personal service corporation. See instructions ▶ ☐			2	NONE
3	Alternative minimum tax (attach Form 4626)			3	145,525.
4	Add lines 2 and 3			4	145,525.
5a	Foreign tax credit (attach Form 1118)	5a	NONE		
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c	145,525.		
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	**Total credits.** Add lines 5a through 5e			6	145,525.
7	Subtract line 6 from line 4			7	
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method - completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method - income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions - attach statement)	9f			
10	**Total.** Add lines 9a through 9f			10	
11	**Total tax.** Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	

Part II-Payments and Refundable Credits

12	2015 overpayment credited to 2016			12	
13	2016 estimated tax payments			13	
14	2016 refund applied for on Form 4466			14	( )
15	Combine lines 12, 13, and 14			15	
16	Tax deposited with Form 7004			16	NONE
17	Withholding (see instructions)			17	13.
18	**Total payments.** Add lines 15, 16, and 17			18	13.
19	Refundable credits from:				
a	Form 2439	19a			
b	Form 4136	19b	115,738.		
c	Form 8827, line 8c	19c			
d	Other (attach statement - see instructions)	19d			
20	**Total credits.** Add lines 19a through 19d			20	115,738.
21	**Total payments and credits.** Add lines 18 and 20. Enter here and on page 1, line 32			21	115,751.

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method: a ☐ Cash b X Accrual c ☐ Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 221100		
b	Business activity ▶ ELECTRIC/GAS PUBLIC		
c	Product or service ▶ ELECTRICITY & NATURA		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group? If "Yes," enter name and EIN of the parent corporation ▶		X
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X

Schedule K Other Information *(continued from page 3)*

		Yes	No
5	At the end of the tax year, did the corporation:		
a	Own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of stock entitled to vote of any foreign or domestic corporation not included on **Form 851,** Affiliations Schedule? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.		X

(i) Name of Corporation	(ii) Employer Identification Number (if any)	(iii) Country of Incorporation	(iv) Percentage Owned in Voting Stock

		Yes	No
b	Own directly an interest of 20% or more, or own, directly or indirectly, an interest of 50% or more in any foreign or domestic partnership (including an entity treated as a partnership) or in the beneficial interest of a trust? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.	X	

(i) Name of Entity	(ii) Employer Identification Number (if any)	(iii) Country of Organization	(iv) Maximum Percentage Owned in Profit, Loss, or Capital
SEE SEPARATE SUBGROUPS			

		Yes	No
6	During this tax year, did the corporation pay dividends (other than stock dividends and distributions in exchange for stock) in excess of the corporation's current and accumulated earnings and profits? See sections 301 and 316		X
	If "Yes," file **Form 5452,** Corporate Report of Nondividend Distributions. If this is a consolidated return, answer here for the parent corporation and on Form 851 for each subsidiary.		
7	At any time during the tax year, did one foreign person own, directly or indirectly, at least 25% of **(a)** the total voting power of all classes of the corporation's stock entitled to vote or **(b)** the total value of all classes of the corporation's stock?		X
	For rules of attribution, see section 318. If "Yes," enter: **(i)** Percentage owned ▶ ______ and **(ii)** Owner's country ▶ ______		
	(c) The corporation may have to file **Form 5472,** Information Return of a 25% Foreign-Owned U.S. Corporation or a Foreign Corporation Engaged in a U.S. Trade or Business. Enter the number of Forms 5472 attached ▶ ______		
8	Check this box if the corporation issued publicly offered debt instruments with original issue discount ▶ ☐ If checked, the corporation may have to file **Form 8281,** Information Return for Publicly Offered Original Issue Discount Instruments.		
9	Enter the amount of tax-exempt interest received or accrued during the tax year ▶ $ 234.		
10	Enter the number of shareholders at the end of the tax year (if 100 or fewer) ▶ ______		
11	If the corporation has an NOL for the tax year and is electing to forego the carryback period, check here ▶ ☒ If the corporation is filing a consolidated return, the statement required by Regulations section 1.1502-21(b)(3) must be attached or the election won't be valid.		
12	Enter the available NOL carryover from prior tax years (don't reduce it by any deduction on line 29a.) ▶ $ 272,627,267.		
13	Are the corporation's total receipts (page 1, line 1a, plus lines 4 through 10) for the tax year **and** its total assets at the end of the tax year less than $250,000?		X
	If "Yes," the corporation isn't required to complete Schedules L, M-1, and M-2. Instead, enter the total amount of cash distributions and the book value of property distributions (other than cash) made during the tax year ▶ $ ______		
14	Is the corporation required to file Schedule UTP (Form 1120), Uncertain Tax Position Statement? See instructions. If "Yes," complete and attach Schedule UTP.		X
15a	Did the corporation make any payments in 2016 that would require it to file Form(s) 1099?	X	
b	If "Yes," did or will the corporation file required Forms 1099?	X	
16	During this tax year, did the corporation have an 80% or more change in ownership, including a change due to redemption of its own stock?		X
17	During or subsequent to this tax year, but before the filing of this return, did the corporation dispose of more than 65% (by value) of its assets in a taxable, non-taxable, or tax deferred transaction?		X
18	Did the corporation receive assets in a section 351 transfer in which any of the transferred assets had a fair market basis or fair market value of more than $1 million?		X
19	During the corporation's tax year, did the corporation make any payments that would require it to file Forms 1042 and 1042-S under chapter 3 (sections 1441 through 1464) or chapter 4 (sections 1471 through 1474) of the Code?		X

Schedule L Balance Sheets per Books

Assets	Beginning of tax year (a)	(b)	End of tax year (c)	(d)
1 Cash		84,590,677.		46,107,230.
2a Trade notes and accounts receivable	496,680,182.		521,790,949.	
b Less allowance for bad debts	(8,633,879.)	488,046,303.	(9,243,332.)	512,547,617.
3 Inventories		253,726,581.		238,273,113.
4 U.S. government obligations				
5 Tax-exempt securities (see instructions)				
6 Other current assets (attach statement)		194,678,712.		180,547,141.
7 Loans to shareholders				
8 Mortgage and real estate loans				
9 Other investments (attach statement)		119,704,018.		125,866,285.
10a Buildings and other depreciable assets	8,201,861,166.		6,035,524,441.	
b Less accumulated depreciation	(4,332,170,383.)	3,869,690,783.	(2,536,370,524.)	3,499,153,917.
11a Depletable assets	415,329,288.		415,542,014.	
b Less accumulated depletion	(111,810,215.)	303,519,073.	(117,969,102.)	297,572,912.
12 Land (net of any amortization)		137,887,068.		134,599,873.
13a Intangible assets (amortizable only)	350,452,549.		340,857,926.	
b Less accumulated amortization	(-292,093,398.)	642,545,947.	(-296,857,363.)	637,715,289.
14 Other assets (attach statement)		533,219,158.		612,083,745.
15 Total assets		6,627,608,320.		6,284,467,122.
Liabilities and Shareholders' Equity				
16 Accounts payable		310,465,932.		279,962,060.
17 Mortgages, notes, bonds payable in less than 1 year		289,289,326.		43,598,481.
18 Other current liabilities (attach statement)		347,678,218.		345,606,696.
19 Loans from shareholders				
20 Mortgages, notes, bonds payable in 1 year or more		1,627,443,226.		1,746,560,720.
21 Other liabilities (attach statement)		1,532,183,144.		1,552,494,839.
22 Capital stock: a Preferred stock	15,000,000.		15,000,000.	
b Common stock	195,804,665.	210,804,665.	195,843,297.	210,843,297.
23 Additional paid-in capital		1,230,119,260.		1,232,477,780.
24 Retained earnings - Appropriated (attach statement)				
25 Retained earnings - Unappropriated		996,355,217.		912,281,806.
26 Adjustments to shareholders' equity (attach statement)		86,895,145.		-35,732,744.
27 Less cost of treasury stock		(3,625,813.)		(3,625,813.)
28 Total liabilities and shareholders' equity		6,627,608,320.		6,284,467,122.

Schedule M-1 **Reconciliation of Income (Loss) per Books With Income per Return**

Note: The corporation may be required to file Schedule M-3. See instructions.

1 Net income (loss) per books		7 Income recorded on books this year not included on this return (itemize): Tax-exempt interest $	
2 Federal income tax per books			
3 Excess of capital losses over capital gains			
4 Income subject to tax not recorded on books this year (itemize):		8 Deductions on this return not charged against book income this year (itemize):	
5 Expenses recorded on books this year not deducted on this return (itemize):		a Depreciation . . . $	
a Depreciation . . . $		b Charitable contributions . $	
b Charitable contributions . $			
c Travel and entertainment . $			
		9 Add lines 7 and 8	
6 Add lines 1 through 5		10 Income (page 1, line 28) - line 6 less line 9	

Schedule M-2 **Analysis of Unappropriated Retained Earnings per Books (Line 25, Schedule L)**

1 Balance at beginning of year	996,355,217.	5 Distributions: a Cash	148,139,828.
2 Net income (loss) per books	64,432,820.	b Stock	
3 Other increases (itemize):		c Property	
		6 Other decreases (itemize):	366,403.
		7 Add lines 5 and 6	148,506,231.
4 Add lines 1, 2, and 3	1,060,788,037.	8 Balance at end of year (line 4 less line 7)	912,281,806.

Form **1120** Department of the Treasury Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2015 or tax year beginning ____________, ending ____________

▶ Information about Form 1120 and its separate instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2015

A Check if:
1a Consolidated return (attach Form 851) X
b Life/nonlife consolidated return
2 Personal holding co. (attach Sch. PH)
3 Personal service corp. (see instructions)
4 Schedule M-3 attached X

TYPE OR PRINT

Name MDU RESOURCES GROUP, INC.
AND SUBSIDIARIES

Number, street, and room or suite no. If a P.O. box, see instructions.
P O BOX 5650

City or town, state, or province, country, and ZIP or foreign postal code
BISMARCK, ND 58506-5650

B Employer identification number 41-0423660
C Date incorporated 03/14/1924
D Total assets (see instructions) $ 6,627,608,320.

E Check if: (1) Initial return (2) Final return (3) Name change (4) Address change

Income	1a	Gross receipts or sales	1a	4,651,050,130.		
	b	Returns and allowances	1b	7,576.		
	c	Balance. Subtract line 1b from line 1a			1c	4,651,042,554.
	2	Cost of goods sold (attach Form 1125-A)			2	3,744,657,727.
	3	Gross profit. Subtract line 2 from line 1c			3	906,384,827.
	4	Dividends (Schedule C, line 19)			4	232.
	5	Interest			5	28,407,068.
	6	Gross rents			6	2,824,922.
	7	Gross royalties			7	
	8	Capital gain net income (attach Schedule D (Form 1120))			8	NONE
	9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)			9	-331,217,623.
	10	Other income (see instructions - attach statement)			10	-10,712,589.
	11	**Total income.** Add lines 3 through 10 ▶			11	595,686,837.
Deductions (See instructions for limitations on deductions.)	12	Compensation of officers (see instructions - attach Form 1125-E) ▶			12	36,437,309.
	13	Salaries and wages (less employment credits)			13	101,573,328.
	14	Repairs and maintenance			14	14,268,969.
	15	Bad debts			15	8,271,835.
	16	Rents			16	33,102,650.
	17	Taxes and licenses			17	85,458,107.
	18	Interest			18	106,468,163.
	19	Charitable contributions			19	NONE
	20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)			20	194,835,967.
	21	Depletion			21	27,322,437.
	22	Advertising			22	2,271,771.
	23	Pension, profit-sharing, etc., plans			23	-1,447,915.
	24	Employee benefit programs			24	13,097,731.
	25	Domestic production activities deduction (attach Form 8903)			25	
	26	Other deductions (attach statement)			26	230,342,357.
	27	**Total deductions.** Add lines 12 through 26 ▶			27	852,002,709.
	28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11			28	-256,315,872.
	29a	Net operating loss deduction (see instructions)	29a			
	b	Special deductions (Schedule C, line 20)	29b	180,163.		
	c	Add lines 29a and 29b			29c	180,163.
Tax, Refundable Credits, and Payments	30	**Taxable income.** Subtract line 29c from line 28 (see instructions)			30	-256,496,035.
	31	Total tax (Schedule J, Part I, line 11)			31	NONE
	32	Total payments and refundable credits (Schedule J, Part II, line 21)			32	177,660.
	33	Estimated tax penalty (see instructions). Check if Form 2220 is attached ▶ ☐			33	
	34	**Amount owed.** If line 32 is smaller than the total of lines 31 and 33, enter amount owed			34	
	35	**Overpayment.** If line 32 is larger than the total of lines 31 and 33, enter amount overpaid			35	177,660.
	36	Enter amount from line 35 you want: **Credited to 2016 estimated tax** ▶ **Refunded** ▶			36	177,660.

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Signature of officer JASON VOLLMER | Date 09/13/2016 | Title VICE PRESIDENT & CAO

May the IRS discuss this return with the preparer shown below (see instructions)? ☐ Yes ☐ No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN
Firm's name ▶			Firm's EIN ▶	
Firm's address ▶			Phone no.	

Schedule C	Dividends and Special Deductions (see instructions)	(a) Dividends received	(b) %	(c) Special deductions (a) x (b)
1	Dividends from less-than-20%-owned domestic corporations (other than debt-financed stock)	232.	70	162.
2	Dividends from 20%-or-more-owned domestic corporations (other than debt-financed stock)		80	
3	Dividends on debt-financed stock of domestic and foreign corporations		see instructions	
4	Dividends on certain preferred stock of less-than-20%-owned public utilities		42	
5	Dividends on certain preferred stock of 20%-or-more-owned public utilities		48	
6	Dividends from less-than-20%-owned foreign corporations and certain FSCs		70	
7	Dividends from 20%-or-more-owned foreign corporations and certain FSCs		80	
8	Dividends from wholly owned foreign subsidiaries		100	
9	**Total.** Add lines 1 through 8. See instructions for limitation			162.
10	Dividends from domestic corporations received by a small business investment company operating under the Small Business Investment Act of 1958		100	
11	Dividends from affiliated group members		100	
12	Dividends from certain FSCs		100	
13	Dividends from foreign corporations not included on lines 3, 6, 7, 8, 11, or 12			
14	Income from controlled foreign corporations under subpart F (attach Form(s) 5471)			
15	Foreign dividend gross-up			
16	IC-DISC and former DISC dividends not included on lines 1, 2, or 3			
17	Other dividends			
18	Deduction for dividends paid on certain preferred stock of public utilities			180,001.
19	**Total dividends.** Add lines 1 through 17. Enter here and on page 1, line 4 ▶	232.		
20	**Total special deductions.** Add lines 9, 10, 11, 12, and 18. Enter here and on page 1, line 29b ▶			180,163.

Schedule J Tax Computation and Payment (see instructions)

Part I-Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)) ▶ X				
2	Income tax. Check if a qualified personal service corporation (see instructions) ▶ ☐			2	NONE
3	Alternative minimum tax (attach Form 4626)			3	NONE
4	Add lines 2 and 3			4	NONE
5a	Foreign tax credit (attach Form 1118)	5a	NONE		
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c			
d	Credit for prior year minimum tax (attach Form 8827)	5d	NONE		
e	Bond credits from Form 8912	5e			
6	**Total credits.** Add lines 5a through 5e			6	NONE
7	Subtract line 6 from line 4			7	NONE
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method - completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method - income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions - attach statement)	9f			
10	**Total.** Add lines 9a through 9f			10	
11	**Total tax.** Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	NONE

Part II-Payments and Refundable Credits

12	2014 overpayment credited to 2015			12	
13	2015 estimated tax payments			13	
14	2015 refund applied for on Form 4466			14	( )
15	Combine lines 12, 13, and 14			15	
16	Tax deposited with Form 7004			16	
17	Withholding (see instructions)			17	
18	**Total payments.** Add lines 15, 16, and 17			18	
19	Refundable credits from:				
a	Form 2439	19a			
b	Form 4136	19b	177,660.		
c	Form 8827, line 8c	19c			
d	Other (attach statement - see instructions)	19d			
20	**Total credits.** Add lines 19a through 19d			20	177,660.
21	**Total payments and credits.** Add lines 18 and 20. Enter here and on page 1, line 32			21	177,660.

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method: a ☐ Cash b X Accrual c ☐ Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 221100		
b	Business activity ▶ ELECTRIC/GAS PUBLIC		
c	Product or service ▶ ELECTRICITY & NATURA		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group? If "Yes," enter name and EIN of the parent corporation ▶		X
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X

Schedule K Other Information *continued* (see instructions)

	Yes	No
5 At the end of the tax year, did the corporation:		
a Own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of stock entitled to vote of any foreign or domestic corporation not included on **Form 851**, Affiliations Schedule? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.		X

(i) Name of Corporation	(ii) Employer Identification Number (if any)	(iii) Country of Incorporation	(iv) Percentage Owned in Voting Stock

	Yes	No
b Own directly an interest of 20% or more, or own, directly or indirectly, an interest of 50% or more in any foreign or domestic partnership (including an entity treated as a partnership) or in the beneficial interest of a trust? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.	X	

(i) Name of Entity	(ii) Employer Identification Number (if any)	(iii) Country of Organization	(iv) Maximum Percentage Owned in Profit, Loss, or Capital
SEE SEPARATE SUBGROUPS			

	Yes	No
6 During this tax year, did the corporation pay dividends (other than stock dividends and distributions in exchange for stock) in excess of the corporation's current and accumulated earnings and profits? (See sections 301 and 316.)		X
If "Yes," file **Form 5452**, Corporate Report of Nondividend Distributions. If this is a consolidated return, answer here for the parent corporation and on Form 851 for each subsidiary.		
7 At any time during the tax year, did one foreign person own, directly or indirectly, at least 25% of **(a)** the total voting power of all classes of the corporation's stock entitled to vote or **(b)** the total value of all classes of the corporation's stock?		X
For rules of attribution, see section 318. If "Yes," enter: **(i)** Percentage owned ▶ ______ and **(ii)** Owner's country ▶ ______		
(c) The corporation may have to file **Form 5472**, Information Return of a 25% Foreign-Owned U.S. Corporation or a Foreign Corporation Engaged in a U.S. Trade or Business. Enter the number of Forms 5472 attached ▶ ______		
8 Check this box if the corporation issued publicly offered debt instruments with original issue discount ▶ ☐ If checked, the corporation may have to file **Form 8281**, Information Return for Publicly Offered Original Issue Discount Instruments.		
9 Enter the amount of tax-exempt interest received or accrued during the tax year ▶ $ 49.		
10 Enter the number of shareholders at the end of the tax year (if 100 or fewer) ▶ ______		
11 If the corporation has an NOL for the tax year and is electing to forego the carryback period, check here ▶ ☒ If the corporation is filing a consolidated return, the statement required by Regulations section 1.1502-21(b)(3) must be attached or the election will not be valid.		
12 Enter the available NOL carryover from prior tax years (do not reduce it by any deduction on line 29a.) ▶ $ ______		
13 Are the corporation's total receipts (page 1, line 1a, plus lines 4 through 10) for the tax year **and** its total assets at the end of the tax year less than $250,000?		X
If "Yes," the corporation is not required to complete Schedules L, M-1, and M-2. Instead, enter the total amount of cash distributions and the book value of property distributions (other than cash) made during the tax year ▶ $ ______		
14 Is the corporation required to file Schedule UTP (Form 1120), Uncertain Tax Position Statement (see instructions)? If "Yes," complete and attach Schedule UTP.		X
15a Did the corporation make any payments in 2015 that would require it to file Form(s) 1099?	X	
b If "Yes," did or will the corporation file required Forms 1099?	X	
16 During this tax year, did the corporation have an 80% or more change in ownership, including a change due to redemption of its own stock?		X
17 During or subsequent to this tax year, but before the filing of this return, did the corporation dispose of more than 65% (by value) of its assets in a taxable, non-taxable, or tax deferred transaction?		X
18 Did the corporation receive assets in a section 351 transfer in which any of the transferred assets had a fair market basis or fair market value of more than $1 million?		X

Schedule L Balance Sheets per Books

Assets	Beginning of tax year (a)	Beginning of tax year (b)	End of tax year (c)	End of tax year (d)
1 Cash		81,854,568.		84,590,677.
2a Trade notes and accounts receivable	602,845,692.		496,680,182.	
b Less allowance for bad debts	(9,180,696.)	593,664,996.	(8,633,879.)	488,046,303.
3 Inventories		300,811,169.		253,726,581.
4 U.S. government obligations				
5 Tax-exempt securities (see instructions)				
6 Other current assets (attach statement)		218,642,717.		194,678,712.
7 Loans to shareholders				
8 Mortgage and real estate loans				
9 Other investments (attach statement)		117,919,573.		119,704,018.
10a Buildings and other depreciable assets	9,206,143,646.		8,201,861,166.	
b Less accumulated depreciation	(4,130,842,878.)	5,075,300,768.	(4,332,170,383.)	3,869,690,783.
11a Depletable assets	415,954,933.		415,329,288.	
b Less accumulated depletion	(104,948,081.)	311,006,852.	(111,810,215.)	303,519,073.
12 Land (net of any amortization)		140,456,596.		137,887,068.
13a Intangible assets (amortizable only)	355,306,234.		350,452,549.	
b Less accumulated amortization	(-289,737,901.)	645,044,135.	(-292,093,398.)	642,545,947.
14 Other assets (attach statement)		325,276,403.		533,219,158.
15 Total assets		7,809,977,777.		6,627,608,320.
Liabilities and Shareholders' Equity				
16 Accounts payable		382,671,164.		310,465,932.
17 Mortgages, notes, bonds payable in less than 1 year		269,449,444.		289,289,326.
18 Other current liabilities (attach statement)		316,318,428.		347,678,218.
19 Loans from shareholders				
20 Mortgages, notes, bonds payable in 1 year or more		1,825,278,303.		1,627,443,226.
21 Other liabilities (attach statement)		1,766,476,288.		1,532,183,144.
22 Capital stock: a Preferred stock	15,000,000.		15,000,000.	
b Common stock	194,754,812.	209,754,812.	195,804,665.	210,804,665.
23 Additional paid-in capital		1,207,188,089.		1,230,119,260.
24 Retained earnings - Appropriated (attach statement)				
25 Retained earnings - Unappropriated		1,762,827,102.		996,355,217.
26 Adjustments to shareholders' equity (attach statement)		73,639,960.		86,895,145.
27 Less cost of treasury stock		(3,625,813.)		(3,625,813.)
28 Total liabilities and shareholders' equity		7,809,977,777.		6,627,608,320.

Schedule M-1 **Reconciliation of Income (Loss) per Books With Income per Return**

Note: The corporation may be required to file Schedule M-3 (see instructions).

1 Net income (loss) per books		7 Income recorded on books this year not included on this return (itemize): Tax-exempt interest $	
2 Federal income tax per books			
3 Excess of capital losses over capital gains			
4 Income subject to tax not recorded on books this year (itemize):		8 Deductions on this return not charged against book income this year (itemize):	
5 Expenses recorded on books this year not deducted on this return (itemize):		a Depreciation $	
a Depreciation $		b Charitable contributions $	
b Charitable contributions $			
c Travel and entertainment $			
		9 Add lines 7 and 8	
6 Add lines 1 through 5		10 Income (page 1, line 28) - line 6 less line 9	

Schedule M-2 **Analysis of Unappropriated Retained Earnings per Books (Line 25, Schedule L)**

1 Balance at beginning of year	1,762,827,102.	5 Distributions: a Cash	144,011,445.
2 Net income (loss) per books	-622,434,595.	b Stock	
3 Other increases (itemize):		c Property	
		6 Other decreases (itemize):	25,845.
		7 Add lines 5 and 6	144,037,290.
4 Add lines 1, 2, and 3	1,140,392,507.	8 Balance at end of year (line 4 less line 7)	996,355,217.

THIS EXHIBIT IS DESIGNATED CONFIDENTIAL UNDER GENERAL PROTECTIVE ORDER

NO. 18-172

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

In the Matter of	)
	)
CASCADE NATURAL GAS CORPORATION,	)
	)
Request for a General Rate Revision.	)

EXHIBIT 109

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

September 27, 2018

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study w/ 163 and 902-2 merged
Summary

Line	Description	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 & 902-2 General Transportation	170 Interruptible core	9xx Special Contracts non-core
1	Billing Determinants								
2	Peak Day Forecast	97,866	49,348	34,175	3,188	936	10,218	-	-
3	Customer Count	72,730	62,493	10,031	148	18	33	4	3
4	Throughput	30,693,226	4,297,744	3,028,642	203,763	162,996	20,109,168	241,847	2,649,066
5	O&M Costs								
6	Gas Supply Related								
7	Gas Planning	83,952	$ 36,617	$ 25,455	$ 2,229	$ 845	$ 16,485	$ 448	$ 1,873
8	Gas Supply	40,673	$ 17,289	$ 12,184	$ 820	$ 656	$ 7,859	$ 973	$ 893
9	Gas Control	77,626	$ 28,852	$ 20,332	$ 1,368	$ 1,094	$ 22,389	$ 1,624	$ 1,966
10	Customer Related								
11	Meter Reading	260,870	$ 218,566	$ 35,085	$ 518	$ 2,080	$ 3,813	$ 462	$ 347
12	Customer Account records and collection	1,318,539	$ 1,126,528	$ 180,832	$ 2,668	$ 324	$ 6,754	$ 819	$ 614
13	Billing Postage & Printing	367,765	$ 315,999	$ 50,725	$ 748	$ 91	$ 167	$ 20	$ 15
14	Uncollectible	319,056	$ 283,335	$ 35,720	$ -	$ -	$ -	$ -	$ -
15	Subtotal: O&M Costs	2,468,481	$ 2,027,187	$ 360,332	$ 8,351	$ 5,091	$ 57,467	$ 4,345	$ 5,708
16	Customer Investment Carrying Costs								
17	Meter	5,485,121	$ 3,181,445	$ 1,630,225	$ 112,925	$ 57,978	$ 425,675	$ 50,098	$ 26,775
18	Service	13,625,113	$ 11,093,183	$ 2,309,911	$ 85,452	$ 18,638	$ 88,453	$ 23,356	$ 6,121
19	Mains	12,185,198	$ 6,913,979	$ 2,213,735	$ 1,008,043	$ 151,080	$ 1,657,012	$ 165,151	$ 76,199
20	Subtotal: Customer Investment Costs	31,295,432	$ 21,188,607	$ 6,153,871	$ 1,206,420	$ 227,696	$ 2,171,139	$ 238,605	$ 109,094
21	System Core Main Carrying Costs								
22	Capacity	34,390,164	$ 17,341,124	$ 12,009,090	$ 1,120,422	$ 328,903	$ 3,590,624	$ -	$ -
23	Commodity	9,820,990	$ 3,805,877	$ 2,682,021	$ 180,443	$ 144,341	$ 2,794,141	$ 214,168	$ -
24	Subtotal: System Core Main Costs	44,211,154	$ 21,147,001	$ 14,691,111	$ 1,300,865	$ 473,244	$ 6,384,765	$ 214,168	$ -
25	LRIC - Distribution	77,975,067	$ 44,362,795	$ 21,205,315	$ 2,515,636	$ 706,031	$ 8,613,371	$ 457,118	$ 114,802
26	Functional Cost Assignment by LRIC								
27	Scheduling & Planning	202,251	$ 82,758	$ 57,971	$ 4,417	$ 2,595	$ 46,733	$ 3,044	$ 4,732
28	Meter Reading, Billing etc.	2,266,229	$ 1,944,429	$ 302,361	$ 3,934	$ 2,495	$ 10,734	$ 1,301	$ 976
29	Meters & Services	19,110,234	$ 14,274,628	$ 3,940,136	$ 198,377	$ 76,616	$ 514,128	$ 73,454	$ 32,895
30	Mains Extensions	12,185,198	$ 6,913,979	$ 2,213,735	$ 1,008,043	$ 151,080	$ 1,657,012	$ 165,151	$ 76,199
31	System Core Mains	44,211,154	$ 21,147,001	$ 14,691,111	$ 1,300,865	$ 473,244	$ 6,384,765	$ 214,168	$ -
32	Total	77,975,067	$ 44,362,795	$ 21,205,315	$ 2,515,636	$ 706,031	$ 8,613,371	$ 457,118	$ 114,802

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study w/ 163 and 902-2 merged
Summary

			101	104	105	111	163 & 902-2	170	9xx
Line	Description	Total	Residential Service	Commercial Service	Industrial Service	Large Volume Service	General Transportation	Interruptible	Special Contracts
			core	core	core	core		core	non-core
33	Non-Gas Revenue at Current Rates	31,989,470	$ 18,646,449	$ 8,435,632	$ 440,188	$ 270,442	$ 3,524,137	$ 297,689	$ 374,934
34	Scheduling and Planning	$ 489,249	$ 200,194	$ 140,233	$ 10,684	$ 6,278	$ 113,048	$ 7,364	$ 11,448
35	Meter Reading & Billing	$ 3,659,158	$ 3,139,564	$ 488,206	$ 6,352	$ 4,029	$ 17,331	$ 2,101	$ 1,576
36	Meters & Services	$ 12,926,276	$ 9,655,443	$ 2,665,131	$ 134,184	$ 51,824	$ 347,759	$ 49,685	$ 22,251
37	Mains	$ 17,042,357	$ 8,417,523	$ 5,070,990	$ 692,609	$ 187,280	$ 2,412,312	$ 113,785	$ 147,858
38	Total LRIC Based Non-gas Rev Req.	$ 34,117,040	$ 21,412,724	$ 8,364,560	$ 843,828	$ 249,411	$ 2,890,450	$ 172,935	$ 183,131
39	Revenue to Cost Ratio	0.94	0.87	1.01	0.52	1.08	1.22	1.72	2.05

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Redacted document upon all parties listed below electronically. Confidential pages have been mailed to those with a Confidential designation. Hermiston Generating Company and Marianne Gardner have not waived paper service, and I have mailed a complete copy of the document to those parties.

Public Utility Commission of Oregon **(C)** Attn: Filing Center PO Box 1088 Salem, OR 97308-1088	STEPHANIE S ANDRUS **(C)** BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@state.or.us
MATTHEW MCVEE **(C)** 825 NE MULTNOMAH PORTLAND OR 97232 matthew.mcvee@pacificorp.com oregondockets@pacificorp.com	JOHN JAMIESON **(C)** 78145 WESTLAND RD HERMISTON OR 97838 jj.jamieson@perennialpower.net
MARIANNE GARDNER **(C)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM OR 97308-1088 marianne.gardner@state.or.us	MICHAEL GOETZ **(C)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND OR 97205 mike@oregoncub.org dockets@oregoncub.org
WILLIAM GEHRKE **(C)** 610 SW BROADWAY STE 400 PORTLAND OR 97206 will@oregoncub.org	MICHAEL PARVINEN **(C)** 8113 W GRANDRIDGE BLVD KENNEWICK WA 99336-7166 michael.parvinen@cngc.com
JOHANNA RIEMENSCHNEIDER **(C)** BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4796 johanna.riemenschneider@doj.state.or.us	ERIC J CALLISTO **(C)** ONE SOUTH PINCKNEY ST STE 700 MADISON WI 53703 ejcallisto@michaelbest.com
LISA F RACKNER **(C)** 419 SW 11TH AVE., SUITE 400 PORTLAND OR 97205 dockets@mrg-law.com	JOCELYN C PEASE **(C)** 419 SW 11TH AVE STE 400 PORTLAND OR 97205 jocelyn@mrg-law.com

CHRISTOPHER E HAWK 121 SW MORRISON ST STE 1575 PORTLAND OR 97204 chawk@grsm.com	

Dated in Portland, Oregon this 27th day of September 2018.

Respectfully submitted,

Tommy A. Brooks, OSB No.076071
Chad M. Stokes, OSB No. 004007
Cable Huston LLP
1001 SW Fifth Ave., Suite 2000
Portland, OR 97204-1136
Telephone: (503) 224-3092
Facsimile: (503) 224-3176
E-Mail: tbrooks@cablehuston.com
cstokes@cablehuston.com

Of Attorneys for Alliance of Western Energy Consumers