BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 344

In the Matter of	)
	)
NORTHWEST NATURAL GAS	)
COMPANY, dba NW NATURAL	)
	)
Request for a General Rate Revision.	)
	)

OPENING TESTIMONY OF MICHAEL P. GORMAN

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

April 20, 2018

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017. I am employed by the firm of Brubaker & Associates, Inc. ("BAI"), regulatory and economic consultants with corporate headquarters in Chesterfield, Missouri. My qualifications are provided in Exhibit AWEC/101.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC").[1/] AWEC members include large energy consumers that purchase sales and transportation services from Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company").

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibit AWEC/101 through Exhibit AWEC/122.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will address the following: first, NW Natural's proposed spread of the revenue deficiency across retail rate classes. Second, I propose adjustments to NW Natural's proposed overall rate of return including return on equity, and the embedded debt cost of NW Natural.

1/ On March 31, 2018 Northwest Industrial Gas Users ("AWEC") merged with the Industrial Customers of Northwest Utilities ("ICNU"), and ICNU changed its name to Alliance of Western Energy Consumers ("AWEC") on April 1, 2018.

Q. DOES THE FACT THAT YOU DID NOT ADDRESS EVERY ISSUE RAISED IN NW NATURAL'S TESTIMONY MEAN THAT YOU AGREE WITH NW NATURAL'S TESTIMONY ON THOSE ISSUES?

A. No. It merely reflects the fact that I did not choose to address all those issues. It should not be read as an endorsement of, or agreement with, NW Natural's position on such issues.

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON CLASS REVENUE SPREAD.

A. The Company's proposed revenue spread does not move classes toward cost of service in a constructive and gradual manner. Indeed, the proposed spread has the effect of penalizing customers that are already priced above cost of service, relative to the system average, and maintaining that rate disparity. I recommend a gradual movement to cost of service in order to produce more rate equity across the various rate classes. I recommend doing this in a gradual manner, so as not to create undue increased stress on any particular rate class.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS ON RATE OF RETURN.

A. I recommend the Public Utility Commission of Oregon ("Commission") award a return on common equity of 9.15%, which is the midpoint of my recommended range of 9.00% to 9.30%. My recommended return reflects NW Natural's current market cost of equity.

I also respond to NW Natural witness Dr. Bente Villadsen's return on equity recommendation. Dr. Villadsen recommended an equity return in the range of 9.7% to 10.3%, with a midpoint of 10.00%.[2/] Dr. Villadsen's recommended return on equity for NW Natural substantially exceeds a fair return on equity for NW Natural's investment risk specifically, and the utility industry's below market risk generally. Dr. Villadsen's

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[2/] Villadsen Direct Testimony at 2-3.

return on equity is simply excessive and results in unjust and unreasonable prices to NW Natural's retail customers.

II. CLASS REVENUE SPREAD

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS REGARDING THE COMPANY'S PROPOSED SPREAD OF ITS REVENUE DEFICIENCY ACROSS ITS RATE CLASSES.

A. My findings and conclusions regarding the Company's proposed spread of the revenue deficiency are summarized as follows:

1. The results of the Company's Long-Run Incremental Cost ("LRIC") Study indicate that current distribution rates, on a relative margin-to-cost basis, for the majority of the Company's rate classes result in those classes paying more than their respective allocated cost of service and, therefore, are deserving of a decrease in current distribution revenues.

2. Though distribution rates based on the LRIC Study would move all rate classes' distribution rates to cost of service, NW Natural has not proposed to move all classes to cost-based rates. Contrary to the results of its LRIC Study, the Company proposes increases in distribution rates for all rate classes which has the effect of continuing existing subsidies.

3. As a result, I recommend an alternative class revenue allocation that moves all classes closer to cost of service based distribution rates. My proposal would give rate decreases to those classes deserving of a rate decrease, while recognizing the principle of gradualism with respect to those classes that are deserving of rate increases as indicated by the Company's LRIC Study results.

Q. HAVE YOU REVIEWED THE RESULTS OF THE LRIC STUDY PERFORMED BY THE COMPANY?

A. Yes, I have reviewed the results of the Company's LRIC Study. The study results indicate that the current distribution rates, on a relative margin-to-cost basis, for the majority of the Company's classes result in those classes paying more than their respective allocated cost of service and, therefore, are deserving of a decrease in current distribution revenues. This is shown on Company witness Mr. Andrew Speer's Exhibit No. 1101, page 1 of 1. On the basis of relative margin to cost at present rates, the classes whose current distribution rates collect more margin revenue than their proposed cost of service as shown in the Company's cost of service study include Industrial Sales Firm (Rates 03ISF, 31ISF, and 32ISF), Commercial Sales Firm (Rates 31CSF and 32CSF), Commercial Transportation Firm (31CTF), Industrial Transportation Firm (31ITF), Transportation Firm (32TF), Commercial Sales Interruptible (32CSI), Industrial Sales Interruptible (32IS), and Transportation Interruptible (32TI). The Company's study also indicates that the current distribution rates paid by Residential Sales Firm (02) and Commercial Sales Firm (Rates 03CSF and 27CSF) under collect their respective proposed cost of service.

Q. DOES THE COMPANY PROPOSE TO MOVE ALL CLASSES' BASE DISTRIBUTION RATES TO COST OF SERVICE?

A. No, it does not. Even though the results of its LRIC Study indicate that many rate classes should see decreases in their distribution rates, the Company actually proposes rate increases for all classes.

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED CLASS REVENUE ALLOCATION?

A. Yes. I have reviewed Exhibit No. 1102 of Company Witness Mr. Andrew Speer's direct testimony which summarizes the Company's proposed class revenue allocation. He proposes to spread the total revenue deficiency of $52,446,470 on approximately an equal percent of current margin basis to all classes. In other words, each class's respective current margin as a percent of total current margin would be used to spread the revenue deficiency. For example, the Residential Sales Firm (Rate 02) class currently provides 66.84% of the Company's current margin. Therefore, under the Company's proposed spread of the revenue deficiency, this class would receive 66.84% of the total revenue deficiency.

It is my understanding that the revenue deficiency includes an increase in margin of $50,496,858, and an increase in gas cost of $1,949,612, for a total revenue deficiency of $52,446,470.

Q DO YOU AGREE WITH MR. SPEER'S PROPOSED CLASS REVENUE ALLOCATION?

A. I do not. Mr. Speer applies each class's percentage of current margin to the total revenue deficiency, which apparently includes some increased gas cost. As a result, the Company's four transportation classes are being allocated some of the Company's increased gas cost, which is incorrect. Classes that do not buy gas from the Company should not be allocated a portion of its gas cost that is incurred to serve other customers. Rather, transportation customers should only be allocated a portion of the Company's non-gas cost of service or a portion of the approved increase in margin in this case.

I have summarized Mr. Speer's proposed class revenue allocation in Exhibit AWEC/102. As shown in this exhibit, Mr. Speer's proposed spread of the revenue deficiency in this proceeding makes a movement to the Company's estimate of the margin cost of service for the Residential Sales Firm (02) and Commercial Sales Firm (Rates 03CSF and 27CSF) classes. However, while he does reflect a movement to cost of service for these classes, the majority of classes are still priced well above Mr. Speer's estimated cost of service.

Q. DO YOU BELIEVE THAT MR. SPEER'S PROPOSED REVENUE SPREAD IN THIS PROCEEDING IS REASONABLE?

A. No, I do not. Mr. Speer proposes to recover the claimed revenue deficiency from all rate classes (excluding Special Contracts), which is at odds with the results of his LRIC Study that indicates many classes should actually receive rate decreases. I believe that an alternative class revenue allocation should be used to give rate decreases to those classes that are deserving of decreases as shown by the LRIC Study, while also recognizing the principle of gradualism and mitigating the cost of service base increases to the Residential Sales Firm (02) rate class and the Commercial Sales Firm (Rates 03CSF and 27CSF) rate classes.

Q. IS IT IMPORTANT TO MOVE CLASSES TOWARD COST OF SERVICE IN RECOVERING A REVENUE DEFICIENCY?

A. Yes. Setting rates on cost of service sends the appropriate price signals to customer classes. As a result, it is important to set rates as close to cost of service as possible while recognizing the principle of gradualism and mitigating rate shock for customer classes when appropriate.

Q. HOW DO YOU RESPOND TO THE COMPANY'S PROPOSED CLASS MARGIN REVENUE ALLOCATION?

A. Moving class revenue allocations to their respective indicated cost of service would result in class distribution rates that better reflect cost causation for all classes. Distribution rates that reflect cost causation for all customers would send proper price signals to all customer classes. The movement to cost-based rates would also put the Company in a better position to collect each respective class cost of service from all of its customer classes and help to eliminate revenue subsidies between rate classes. That being said, AWEC recognizes the need to gradually move classes to cost-based rates so that no class experiences rate shock. While AWEC's proposed margin revenue allocation does not completely move all rates to cost of service, it does move classes closer to cost of service than the class revenue allocation proposed by the Company while recognizing the principle of gradualism. Under AWEC's proposal, no class is subject to an increase in current distribution rates that is more than 1.5 times the system average margin increase which under the Company's filed case would be 21.6% to 1.5x the average increase of 14.4%, excluding special contract customers. AWEC's proposed class revenue allocation reasonably moves each class closer to its respective cost of service, while ensuring that no class is burdened by an exorbitant increase in this case.

I have summarized the rate classes' present margin revenue, AWEC's proposed margin revenue at proposed rates that results in a gradual movement toward cost of service, and the Company's calculated margin cost of service for each rate class in Exhibit AWEC/103, Gorman/1.

Q. WHAT IS AWEC'S RECOMMENDED CLASS REVENUE ALLOCATION?

A. AWEC's recommended class revenue allocation is shown in Exhibit AWEC/103, Gorman/2. Though many rate classes are deserving of much large decreases in current margin revenues as indicated in the Company's LRIC study, as discussed in the testimony of my colleague, Mr. Edward Finklea, AWEC proposes to cap the decrease at 7.5% for those classes deserving of a decrease as indicated in the Company's LRIC study.

III. RATE OF RETURN

Q. PLEASE DESCRIBE THIS SECTION OF YOUR TESTIMONY.

A. In this section, I will provide some observable market evidence, provide credit metrics to assess the reasonableness of rate of return positions, and provide a detailed analysis to demonstrate a rate of return that will support NW Natural's financial integrity and access to capital. I also comment on market-based models to estimate the current market-required rate of return investors demand to assume the risk of an investment similar to NW Natural's common equity securities.

III.A. CURRENT CAPITAL MARKET

Q. DO YOU BELIEVE MARKET-BASED MODELS PRODUCE REASONABLE ESTIMATES OF NW NATURAL'S CURRENT COST OF EQUITY?

A. Yes. I believe the application of a Discounted Cash Flow ("DCF") analysis, risk premium, and Capital Asset Pricing Model ("CAPM") produces reasonable and accurate estimates of the current market cost of equity for NW Natural and other utility companies of similar investment risk.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE DCF MODELS PRODUCE A REASONABLE ESTIMATE OF NW NATURAL'S MARKET COST OF COMMON EQUITY.

A. The results of the DCF model are economically logical in comparison to alternative income investments and exhibit robust growth outlooks.

The DCF results generally produce economically logical results by comparison of the two major components of the DCF return: (1) the dividend yield, and (2) the growth rate. The utility stock investments are both income investments and growth investments. Hence, the stock yield component of the DCF model can be compared to alternative income investments of comparable risk to assess how it compares to alternative market investments.

On my Exhibit AWEC/104, Gorman/2, I show a comparison of utility stock dividend yields compared to A-rated utility bond yields. This is an approximate risk comparable investment for the income component of a utility stock DCF return. As shown on this exhibit, utility dividend yields are around 2.5%, which compares to A-rated utility bond yields of around 4.0%. This spread of approximately 150 basis points is relatively low in comparison to the 12-year average shown on this schedule. A high utility stock yield relative to an A-rated utility bond yield is an indication that the DCF model yield component is higher than normal and thus is a robust income return relative to alternative similar risk income investments.

From a DCF growth perspective, utility stocks are also producing strong growth outlooks relative to the past. The industry's historical growth in dividends has been around 4.0% to 4.5%. (*Id*., Gorman/3). This compares to outlooks for future growth in utility dividends and earnings of around 6.0%. These growth outlooks will be discussed in more detail later in this testimony. As such, a DCF return on utility stocks reflects a yield component and a growth component that both reflect robust return outlooks for utility stock investors, and are economically logical in comparison to alternative investments of comparable risk.

Further, as discussed in more detail later in this testimony, the CAPM return also reflects a relatively low risk-free rate by historical standards, but this low risk-free rate is combined with a market risk premium that is above historical actual achieved market risk premiums relative to Treasury bond investments. Thus, the CAPM return estimate is also economically logical based on observable market fundamentals and alternative investments.

Therefore, the current market-derived models are producing reasonable results.

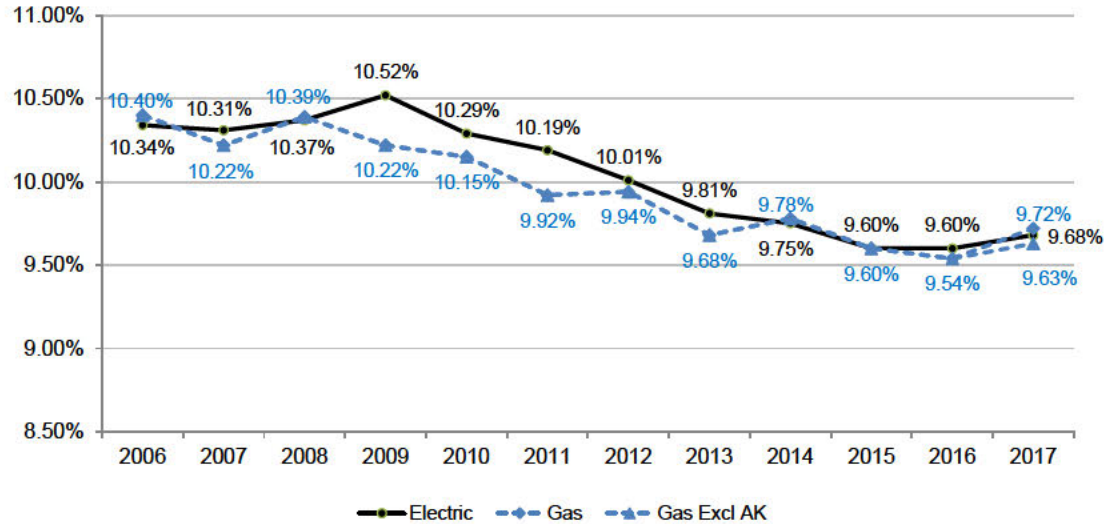
III.B. UTILITY INDUSTRY AUTHORIZED RETURNS ON EQUITY, ACCESS TO CAPITAL, AND CREDIT STRENGTH

Q. PLEASE DESCRIBE THE OBSERVABLE EVIDENCE ON TRENDS IN AUTHORIZED RETURNS ON EQUITY FOR REGULATED UTILITIES, UTILITIES' CREDIT STANDING, AND UTILITIES' ACCESS TO CAPITAL USED TO FUND INFRASTRUCTURE INVESTMENT.

A. Authorized returns on equity for both electric and gas utilities have been steadily declining over the last ten years, as illustrated in Figure 1 below. Many recent authorized returns on equity for electric and gas utilities have declined downward to about 9.60% to 9.7%.

FIGURE 1

Authorized Returns on Equity*
(Exclude Limited Issue Riders)



Source and Note:
S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions -- January - December 2017, January 30, 2018 at pages 5 and 6.
* Electric Returns exclude Limited Issue Riders.
* RRA excludes the Alaska NSTAR decision from its calculations.

While the declines in authorized returns on equity are public knowledge and align with declining capital market costs, utilities have been able to maintain a stable outlook and have been able to attract large amounts of capital at low cost to fund very large capital programs.

I would note, that while the industry average returns on equity increase slightly at year-end 2017 relative to the previous 18 months, the majority of authorized returns on equity over the last 24 months have been relatively stable. As shown on my Exhibit AWEC/105, approximately 80% of authorized returns on equity have fallen in the range of 9.3% to 9.8%.

Q. PLEASE DESCRIBE THE RATINGS ACTIVITY THAT CREDIT RATING AGENCIES HAVE TAKEN WITH RESPECT TO THE REGULATED UTILITY INDUSTRY DURING THE PERIOD OF DECLINING RETURNS ON EQUITY.

A. The credit rating changes for the electric and gas utility industries reflect a significant strengthening of the industry credit outlook.

The natural gas utility industry credit rating changes are shown in Table 1 below. The gas industry changes in credit ratings are similar to the electric utilities. In 2009, 42% of the gas industry had a credit rating in the BBB category with 28% below BBB+. By the end of 2016, all gas utilities' credit ratings improved to BBB+ or higher.

TABLE 1

S&P Ratings by Category
Natural Gas Utilities
(Year End)

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017
A or higher	57%	57%	50%	50%	38%	33%	33%	44%	56%
A-	0%	0%	0%	0%	38%	33%	33%	22%	11%
BBB+	14%	14%	38%	38%	13%	22%	33%	33%	33%
BBB	14%	14%	0%	0%	0%	0%	0%	0%	0%
BBB-	14%	14%	13%	13%	13%	11%	0%	0%	0%
Below BBB-	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%

As of December 31, 2017.
Source: S&P CAPITAL IQ, downloaded 2/15/18.
Note: Subsidiary rating is used if parent not rated.

Q. HAVE UTILITIES BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT INFRASTRUCTURE CAPITAL PROGRAMS?

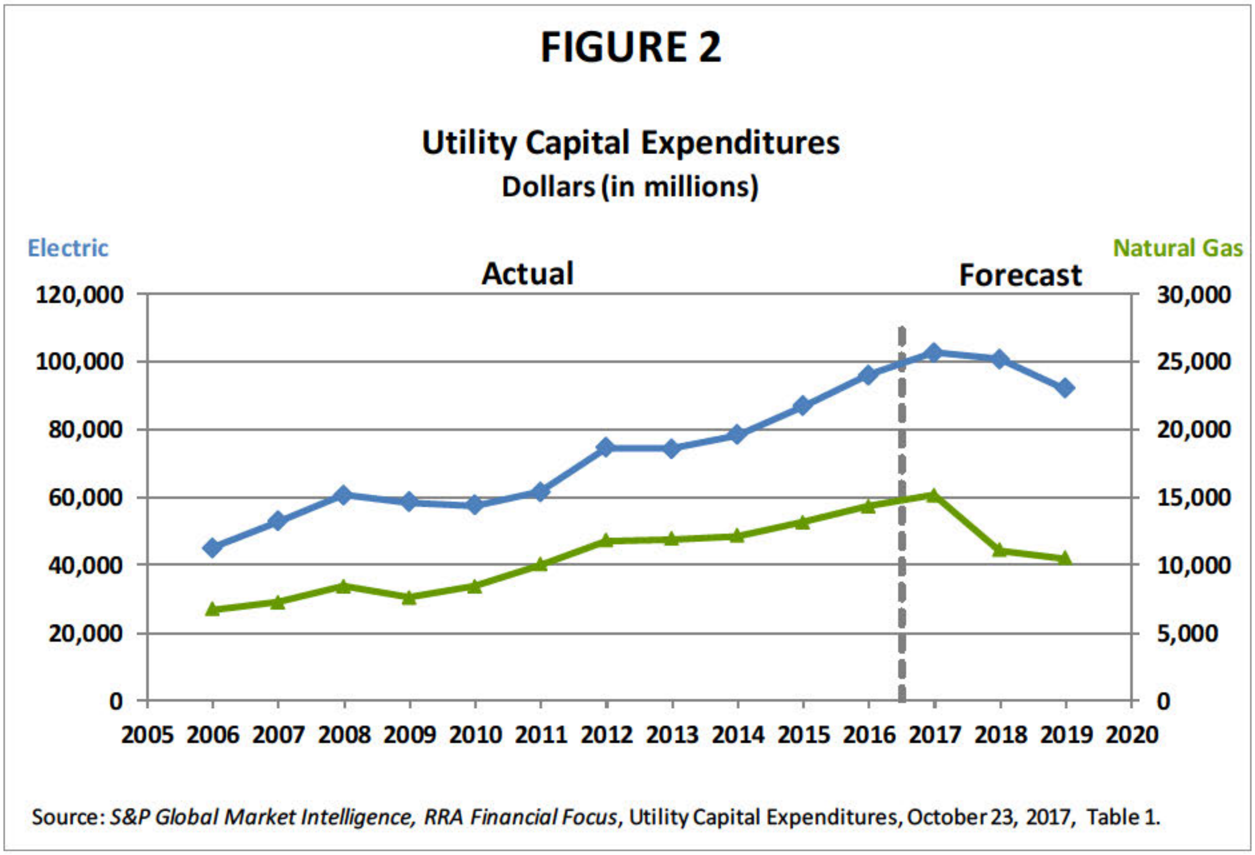
A. Yes. In its October 23, 2017 Capital Expenditure Update report, *RRA Financial Focus*, a division of S&P Global Market Intelligence, made several comments about utility capital investments:

> • Projected 2017 capital expenditures for the 53 gas and electric utilities in the RRA universe has stayed steady at about $117.5 billion, which would be an all-time high for the sector.

> • CapEx projections for the longer term increased modestly from our previous analysis in March 2017, rising to $111.8 billion for 2018 and $102.4 billion for 2019, as companies' plans for future projects solidified and new opportunities arose.
>
> The nation's electric and gas utilities are investing in infrastructure to upgrade aging transmission and distribution systems, build new natural gas, solar and wind generation and implement new technologies. We expect considerable levels of spending to serve as the basis for solid profit expansion for the foreseeable future.
>
> * * *
>
> From a natural gas perspective, many utilities are participating in the sizable and ongoing expansion of the nation's gas midstream network. In addition, replacement of mature gas distribution infrastructure has gained widespread momentum and is likely to continue at material levels for many years, considering state and federal mandates to address safety.
>
> * * *
>
> For gas utilities, the CapEx/OCF ratio has fluctuated far more substantially than for electric utilities. Gas utilities saw large swings in the ratio from 2000 through 2012, with a peak of 1.5x in 2000 and a low of 0.7 in 2009. Since reaching 1.4x in 2012, the ratio appears to have stabilized somewhat, although 2015 was slightly lower at 1.0x, before jumping up again to 1.3x in 2016, and dipping down to 1.1x in the first half of 2017.[3/]

Indeed, historical versus projected outlooks for the electric and gas industries' capital investments are shown in Figure 2 below. As shown in this graph, gas industry investment outlooks are expected to be considerably higher in the forecast (2017-2019), relative to the last ten-year historical period. As noted by S&P Global Market Intelligence, capital investment is exceeding internal sources of funds to the gas utilities, requiring them to seek external capital to fund capital investments.

3/ S&P Global Market Intelligence, RRA Financial Focus: "Utility Capital Expenditures: 2017 CapEx projections hold steady, 2018 and 2019 edge up," October 23, 2017, at 1 and 4.



As shown in Figure 2 above, the capital investments for the electric utility industry are significantly higher than the capital investments for the gas industry but they follow the same trend over the historical and forecasted period.

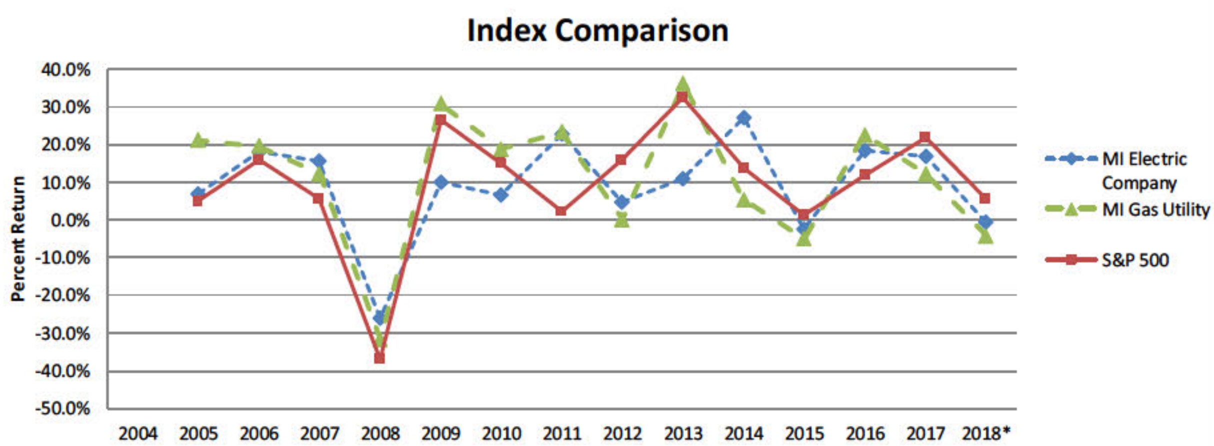
Q. IS THERE EVIDENCE OF ROBUST VALUATIONS OF GAS UTILITY SECURITIES?

A. Yes. Robust valuations are an indication that utilities can sell securities at high prices, which is a strong indication that they can access equity capital under reasonable terms and conditions, and at relatively low cost. As shown on Exhibit AWEC/104, the historical valuation of the electric and gas utilities followed by *Value Line*, based on a price-to-earnings ("P/E") ratio, price-to-cash flow ("P/CF") ratio, and market price-to-book value ("M/B") ratio, indicates utility security valuations today are very strong and robust relative to the last 11-15 years. These strong valuations of utility stocks indicate that utilities have access to equity capital under reasonable terms and at lower costs.

Q. PLEASE DESCRIBE UTILITY STOCK PRICE PERFORMANCE OVER THE LAST SEVERAL YEARS.

A. As shown in Figure 3 below, S&P Global Market Intelligence ("MI") has recorded utility stock price performance compared to the market. The industry's stock performance data from 2004 through January 2018 shows that the MI Electric Company and Gas Utility Indexes have followed the market through downturns and recoveries. However, utility investments have exhibited less volatile movement during extreme market downturns. This more stable price performance for utilities supports my conclusion that utility stock investments are regarded by market participants as moderate- to low-risk investments.

FIGURE 3



Source: S&P Global Market Intelligence.
***Data through January 2018**

Q. HOW SHOULD THE COMMISSION USE THIS MARKET INFORMATION IN ASSESSING A FAIR RETURN FOR NW NATURAL?

A. Market evidence is quite clear that capital market costs are near historically low levels. Authorized returns on equity have fallen to the mid 9.0% area; utilities continue to have access to large amounts of external capital to fund large capital programs; and utilities' investment grade credit standings are mostly stable. The Commission should carefully weigh all this important observable market evidence in assessing a fair return on equity for NW Natural.

III.C. FEDERAL RESERVE AND MARKET CAPITAL COSTS OUTLOOK

Q. HAVE YOU CONSIDERED CONSENSUS MARKET OUTLOOKS FOR CHANGES IN INTEREST RATES IN FORMING YOUR RECOMMENDED RETURN ON EQUITY IN THIS CASE?

A Yes. The outlooks for changes in interest rates, inflation, and Gross Domestic Product ("GDP") growth have been impacted by expectations that the Federal Reserve Bank Open Market Committee ("FOMC") will raise short-term interest rates. Consensus economists are expecting continued increases in the Federal Funds Rate as the FOMC continues to normalize interest rates in response to the strengthening of the U.S. economy.

This is evident from a comparison of current and forecasted changes in the Federal Funds Rate, as shown in Table 2 below. However, while the Federal Funds Rate is expected to increase over the next several years, consensus economists are not projecting significant increases in long-term interest rates. This is also illustrated in Table 2 below.

TABLE 2

Blue Chip Financial Forecasts
Projected Federal Funds Rate, 30-Year Treasury Bond Yields, and GDP Price Index

Publication Date	2Q 2017	3Q 2017	4Q 2017	1Q 2018	2Q 2018	3Q 2018	4Q 2018	1Q 2019	2Q 2019
Federal Funds Rate									
Sep-17	**0.9**	1.2	1.3	1.5	1.6	1.8	2.0		
Oct-17		1.2	1.2	1.4	1.6	1.8	2.0	2.2	
Nov-17		**1.2**	1.2	1.4	1.6	1.8	2.0	2.1	
Dec-17		**1.2**	1.2	1.4	1.6	1.8	2.0	2.2	
Jan-18			1.2	1.5	1.7	1.9	2.0	2.2	2.4
Feb-18			**1.2**	1.5	1.7	1.9	2.1	2.3	2.5
Mar-18			**1.2**	1.5	1.7	1.9	2.2	2.3	2.5
T-Bond, 30 yr.									
Sep-17	**2.9**	2.9	3.1	3.2	3.4	3.5	3.6		
Oct-17		2.8	2.9	3.1	3.3	3.4	3.5	3.6	
Nov-17		**2.8**	3.0	3.1	3.3	3.4	3.5	3.6	
Dec-17		**2.8**	2.9	3.1	3.3	3.4	3.5	3.6	
Jan-18			2.8	3.0	3.1	3.3	3.4	3.5	3.6
Feb-18			**2.8**	3.0	3.1	3.3	3.4	3.5	3.6
Mar-18			**2.8**	3.1	3.2	3.4	3.5	3.6	3.7
GDP Price Index									
Sep-17	**1.0**	1.7	2.0	2.1	2.0	2.1	2.1		
Oct-17		1.7	2.0	1.9	1.9	2.1	2.1	2.2	
Nov-17		**2.2**	2.0	1.9	2.0	2.1	2.1	2.2	
Dec-17		**2.2**	2.2	2.0	1.9	2.1	2.1	2.2	
Jan-18			2.2	2.0	1.9	2.0	2.1	2.2	2.0
Feb-18			**2.4**	2.0	2.0	2.1	2.1	2.2	2.1
Mar-18			**2.4**	2.1	2.0	2.2	2.1	2.2	2.2

Source and Note:
Blue Chip Financial Forecasts, September 2017 through March 2018.
Actual Yields in Bold

I note that the six increases in the Federal Funds Rate experienced over the last few years have not caused comparable changes in outlooks for changes in long-term interest rates. This is illustrated on my Exhibit AWEC/106. As shown on that exhibit, the actions taken by the FOMC to increase the Federal Funds Rate have simply flattened the yield curve, and have not resulted in an equal increase in long-term interest rates. This is significant because cost of common equity is impacted by long-term interest rates, not short-term interest rates. As a result, the recent increases in the Federal Funds Rate, and the expectation of continued increases in the Federal Funds Rate, have not, and are not expected to, significantly impact long-term interest rates.

The Federal Reserve has also recently implemented a strategy to begin to unwind its balance sheet position in long-term securities. The Federal Reserve built up approximately $4.7 trillion of Treasury and mortgage-backed security holdings as part of a quantitative easing ("QE") program that spanned 2008 to 2014. During this QE program, the Federal Reserve procured long-term securities in an effort to support the Federal Reserve's monetary policy, mitigate long-term interest rates, and to support a recovering economy.

The Federal Reserve recently started to unwind its balance sheet positions of mortgage-backed securities and Treasury bonds. The Federal Reserve now engages in a slow and systematic reduction to its balance sheet position. This Federal Reserve balance sheet action has been fully disclosed to the market, and the impact on capital markets valuation and interest rates is captured in current and projected interest rates.

For these reasons, the Federal Reserve actions on short-term interest rates have not resulted in matched increases in long-term interest rates. Further, the Federal Reserve's proposed plan for unwinding its balance sheet position is not expected to have a significant impact on long-term interest rates. All this indicates that the Federal Reserve's monetary policy changes related to a strengthening economy have not and are not expected to increase long-term interest rates. Further, this outlook is reflected in consensus economists' forecasts of long-term interest rates, which indicate a relatively low capital market cost period for at least the intermediate period.

Q. HAVE LONGER-TERM PROJECTIONS OF INTEREST RATES MODERATED MORE RECENTLY RELATIVE TO THE LAST FEW YEARS?

A. Yes. This is shown below in Table 3. There, I show the prevailing quarterly average Treasury bond yield, and the projections of Treasury bond yields two years out, and five to ten years out. Significantly, Treasury bond yields in 2017 have been relatively moderate and comparable to those in 2015 and 2016; however, projections of future Treasury bond yields are now much lower five to ten years out than they were over the last three years. Indeed, in 2014, Treasury bond yields five to ten years out were projected to increase to 5.6% from 3.26% to 3.79% prevailing yields. These five to ten-year projections steadily declined through 2015 and 2016. Most recently, long-term projected Treasury bond yields are now expected to remain relatively low in the 4.1% to 4.3% area.

While the accuracy of projected increases in interest rates is at best problematic, what is significant is that consensus market economists now are projecting out relatively low levels of capital market costs over the next five to ten years. This outlook represents a material moderation in capital market costs over this intermediate forecast period.

TABLE 3

30-Year Treasury Bond Yield Actual Vs. Projection

Description	Quarterly Average	2-Year Projected	5- to 10-Year Projected
2014			
Q1	3.79%	4.40%	5.0% - 5.5%
Q2	3.69%	4.50%	
Q3	3.44%	4.40%	5.3% - 5.6%
Q4	3.26%	4.30%	
2015			
Q1	2.97%	4.00%	4.9% - 5.1%
Q2	2.55%	3.70%	
Q3	2.83%	4.00%	4.8% - 5.0%
Q4	2.84%	3.90%	
2016			
Q1	2.96%	3.80%	4.5% - 4.8%
Q2	2.72%	3.60%	
Q3	2.64%	3.40%	4.3% - 4.6%
Q4	2.29%	3.10%	
2017			
Q1	2.82%	3.70%	4.2% - 4.5%
Q2	3.05%	3.80%	
Q3	2.91%	3.70%	4.3% - 4.5%
Q4	2.80%	3.60%	
2018			
Q1	2.82%	3.60%	4.1% - 4.3%

Sources:
Blue Chip Financial Forecasts ,
December 2013 through March 2018.

III.D. NW NATURAL'S INVESTMENT RISK

Q. PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF THE INVESTMENT RISK OF NW NATURAL.

A. The market's assessment of NW Natural's investment risk is described by credit rating analysts' reports. NW Natural's current corporate bond ratings from S&P and Moody's are A+ and A3, respectively.[4/] NW Natural's outlook is "Stable" from S&P, and "Negative" from Moody's.

Specifically, S&P states:

> **Outlook: Stable**
>
> S&P Global Ratings' stable rating on Portland, Ore.-based Northwest Natural Gas Co. (NWN) reflects our expectation of strong financial and operating performance and regulatory support over the next two years. We expect funds from operations (FFO) to debt to be between 18% and 20% during this period.
>
> * * *
>
> **Business Risk: Excellent**
>
> We assess NWN's business risk based on the company's very low risk regulated gas distribution operations (accounts for about 90%-95% of consolidated cash flows) and its unregulated natural gas storage business, where we ascribe higher risk. About 90% of NWN's roughly 725,000 customers are in Oregon, primarily in the Salem and Portland metropolitan areas, remainder in Washington. The company benefits from stable and supportive regulatory environments in both of the jurisdictions it operates in, with purchased gas adjustments and environmental cost deferral in both jurisdictions, and decoupling, forward-looking test years, and weather normalization mechanisms in Oregon. These mechanisms reduce regulatory lag in collection of associated costs and help bolster cash flow stability outside of rate cases. The utility's cash flows are further stabilized by a large, stable residential customer base (about 90% of all customers) with limited exposure to more cyclical commercial and industrial customers. A history of safe and reliable services also strengthens the company's business profile.

[4/] NW Natural/305, Burkhartsmeyer/Page 1 of 1.

> After factoring in these components, we view NWN's business risk profile at the stronger end of the excellent category, supported by the company's ability to effectively manage the regulatory process, which helps support higher and more stable profitability.
>
> **Financial Risk: Intermediate**
>
> Under our base-case scenario, with elevated capital spending in 2017 to support the Mist expansion, modestly rising dividend payments, and cost recovery through various regulatory mechanisms and rate cases, we expect the company's FFO to debt measures will be about 18%-20% in 2017 and 2018. Since the range of projected FFO to total debt is solidly in the middle of the intermediate financial risk profile category, it supports a modest cushion to the ratings. We assess NWN's financial risk profile based on financial ratios that are measured against the most relaxed benchmarks used for corporate issuers, reflecting the low-risk nature of the company's natural gas distribution operations in supportive regulatory environments. We assume that NWN will continue to manage regulatory risk well and fully recover capital spending on a timely basis.
>
> * * *
>
> **Group Influence**
>
> NWN is subject to the group rating methodology criteria. We view NWN as the parent and driver of the group credit profile. As a result, NWN's group and stand-alone credit profiles are the same at 'a+'.[5/]

III.E. NW NATURAL'S PROPOSED CAPITAL STRUCTURE

Q. WHAT IS NW NATURAL'S PROPOSED CAPITAL STRUCTURE?

A. NW Natural's proposed capital structure is shown below in Table 4. This actual capital structure ending on March 31, 2017 is sponsored by NW Natural witness Mr. Frank Burkhartsmeyer.

[5/] NW Natural/304, Burkhartsmeyer/Pages 9-10 of 13.

TABLE 4

NW Natural's Proposed Capital Structure
(October 31, 2019)

Description	Weight
Long-Term Debt	50.00%
Common Equity	50.00%
Total	100.00%

Source: NW Natural/300 at 3.

I will not take issue with NW Natural's proposed capital structure.

III.F. Embedded Cost of Debt

Q. WHAT IS THE COMPANY'S EMBEDDED COST OF DEBT?

A. Mr. Burkhartsmeyer is proposing an embedded cost of debt of 5.23% as developed on page 3 of his NW Natural/301.

III.G. RETURN ON EQUITY

Q. PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."

A. A utility's cost of common equity is the expected return that investors require on an investment in the utility. Investors expect to earn their required return from receiving dividends and through stock price appreciation.

Q. PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A. In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: Bluefield Water Works &

Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

These decisions identify the general financial and economic standards to be considered in establishing the cost of common equity for a public utility. Those general standards provide that the authorized return should: (1) be sufficient to maintain financial integrity; (2) attract capital under reasonable terms; and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

Q. PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE NW NATURAL'S COST OF COMMON EQUITY.

A. I have used several models based on financial theory to estimate NW Natural's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; a (4) risk premium analysis; and (5) a Capital Asset Pricing Model ("CAPM"). I have applied these models to a group of publicly traded utilities with investment risk similar to NW Natural.

III.H. RISK PROXY GROUP

Q. PLEASE DESCRIBE HOW YOU IDENTIFIED A PROXY UTILITY GROUP TO ESTIMATE NW NATURAL'S CURRENT MARKET COST OF EQUITY.

A. My natural gas proxy group is the same as the proxy group relied on by NW Natural's witness, Dr. Villadsen. Even though there are several companies that I would have excluded following my standard criteria, to limit the issues in this regulatory proceeding and preserve the limited sample size, I have retained all natural gas utilities included in Dr. Villadsen's proxy group.

Q. PLEASE DESCRIBE WHY YOU BELIEVE YOUR PROXY GROUP IS REASONABLY COMPARABLE IN INVESTMENT RISK TO NW NATURAL.

A. The proxy group shown in Exhibit AWEC/107, has an average corporate credit rating from S&P of A, which is a notch lower than NW Natural's A+ credit rating from S&P. The proxy group has an average corporate credit rating from Moody's of A3, which is identical to NW Natural's credit rating from Moody's. Based on this information, I believe my proxy group is reasonably comparable in investment risk to NW Natural.

I also note that the proxy group has an average common equity ratio of 47.5% (including short-term debt) from S&P Global Market Intelligence ("MI") and 54.8% (excluding short-term debt) from *The Value Line Investment Survey* ("*Value Line*"). The Company's proposed common equity ratio of 50% is consistent with the average proxy group common equity ratio and will produce a total financial risk profile for NW Natural that is in line with the investment risk of the proxy group.

III.I. DISCOUNTED CASH FLOW MODEL

Q. PLEASE DESCRIBE THE DCF MODEL.

A. The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \; .\,.\,.\,. \; \frac{D_\infty}{(1+K)^\infty} \qquad \text{(Equation 1)}$$

P_0 = Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return otherwise known as "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A. As shown in Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

Q. WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A. I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on March 16, 2018. An average stock price is less susceptible to market price variations than a price at a single point in time. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value.

A 13-week average stock price reflects a period that is still short enough to contain data that reasonably reflects current market expectations but the period is not so short as to be susceptible to market price variations that may not reflect the stock's long-term value. In my judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and the need to capture sufficient data to smooth out aberrant market movements.

Q. WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A. I used the most recently paid quarterly dividend as reported in *Value Line*.[6/] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above.

Q. WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A. There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market-required return on common equity, one must attempt to estimate investors' consensus about what the dividend, or earnings growth rate, will be and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[7/] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence investors' decisions, which are captured in observable stock prices more so than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations. I used the average of analysts' growth rate

6/ *The Value Line Investment Survey*, March 2, 2018.

7/ *See, e.g.,* David Gordon, Myron Gordon, and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

estimates from three sources: Zacks, MI,[8] and Reuters. All such projections were available on March 16, 2018, as reported online.

Each consensus growth rate projection is based on a survey of security analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not as reliably predict consensus investor outlooks as does a consensus of market analysts' projections. The consensus estimate is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations.

Q. WHAT ARE THE GROWTH RATES YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A. The growth rates I used in my DCF analysis are shown in Exhibit AWEC/108. The average growth rate for my proxy group is 5.97%.

Q. WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A. As shown in Exhibit AWEC/109, the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 8.94% and 8.58%, respectively.

Q. DO YOU HAVE ANY COMMENTS ON THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS?

A. Yes. The constant growth DCF analysis for my proxy group is based on a group average long-term sustainable growth rate of 5.97%. The three- to five-year growth rates are significantly higher than my estimate of a maximum long-term sustainable growth rate of

[8] S&P Global Market Intelligence.

4.20%, which I discuss later in this testimony. I believe the constant growth DCF analysis produces a reasonable high-end return estimate from my DCF studies.

Q. HOW DID YOU ESTIMATE A MAXIMUM LONG-TERM SUSTAINABLE GROWTH RATE?

A. A long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. Hence, the long-term maximum sustainable growth rate for a utility investment is best proxied by the projected long-term Gross Domestic Product ("GDP"). *Blue Chip Economic Indicators* projects that over the next five and ten years, the U.S. nominal GDP will grow approximately 4.20%. These GDP growth projections reflect a real growth outlook of 2.0% and an inflation outlook of 2.1% going forward. As such, the average growth rate over the next ten years is approximately 4.20%, which is a reasonable proxy of long-term sustainable growth.[9/]

In my multi-stage growth DCF analysis, I discuss academic and investment practitioner support for using the projected long-term GDP growth outlook as a maximum sustainable growth rate projection. Accordingly, recognizing the long-term GDP growth rate as a maximum sustainable growth is logical, and is generally consistent with academic and economic practitioner accepted practices.

III.J. SUSTAINABLE GROWTH DCF

Q. PLEASE DESCRIBE HOW YOU ESTIMATED A SUSTAINABLE LONG-TERM GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A. A sustainable growth rate is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment. These reinvested earnings increase the earnings base (rate base). Earnings grow when plant funded by reinvested

9/ *Blue Chip Economic Indicators,* March 10, 2018, at 14.

earnings is put into service, and the utility is allowed to earn its authorized return on such additional rate base investment.

The internal growth methodology is tied to the percentage of earnings retained in the company and not paid out as dividends. The earnings retention ratio is 1 minus the dividend payout ratio. As the payout ratio declines, the earnings retention ratio increases. An increased earnings retention ratio will fuel stronger growth because the business funds more investments with retained earnings.

The payout ratios of the proxy group are shown in my Exhibit AWEC/110. These dividend payout ratios and earnings retention ratios can be used to develop a sustainable long-term earnings retention growth rate. A sustainable long-term earnings retention ratio will help gauge whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time.

The data used to estimate the long-term sustainable growth rate is based on NW Natural's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit AWEC/111, the average sustainable growth rate for the proxy group using this internal growth rate model is 8.36%.

Q. DO YOU HAVE ANY COMMENTS CONCERNING YOUR SUSTAINABLE GROWTH RATE?

A. Yes. As shown on my Exhibit AWEC/111, Gorman/1, the internal growth by reinvesting retained earnings is about 6.26%. However, after reflecting sales of additional shares, the sustainable growth rate is increased from 6.26% up to 8.36%. This significant impact on the internal growth caused by sales of additional shares is not sustainable. Therefore, I conclude that the three- to five-year projection of growth does not produce a reasonable estimate of sustainable growth.

Q. WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE LONG-TERM GROWTH RATES?

A. A DCF estimate based on these sustainable growth rates is developed in Exhibit AWEC/112. As shown there, a sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 11.38% and 10.97%, respectively.

Q. DO YOU HAVE ANY COMMENTS ON THE RESULTS OF YOUR SUSTAINABLE CONSTANT GROWTH DCF ANALYSIS?

A. Yes. The results of the sustainable growth DCF model are based on growth rates that are excessive and not sustainable in long-run. As discussed above, these growth rates reflect sales of additional shares and while they can be achieved in the short-run they cannot be sustained in the long-run. Hence, the results of this model are excessive and significantly overstate a reasonable return on equity for a low risk regulated company like NW Natural.

III.K. MULTI-STAGE GROWTH DCF MODEL

Q. HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A. Yes. My first constant growth DCF is based on consensus analysts' growth rate projections so it is a reasonable reflection of rational investment expectations over the next three to five years. The limitation on this constant growth DCF model is that it cannot reflect a rational expectation that a period of high or low short-term growth can be followed by a change in growth to a rate that is more reflective of long-term sustainable growth. Hence, I performed a multi-stage growth DCF analysis to reflect this outlook of changing growth expectations.

Q. WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?

A. Analyst-projected growth rates over the next three to five years will change as utility earnings growth outlooks change. Utility companies go through cycles in making investments in their systems. When utility companies are making large investments, their rate base grows rapidly, which in turn accelerates earnings growth. Once a major construction cycle is completed or levels off, growth in the utility rate base slows and its earnings growth slows from an abnormally high three- to five-year rate to a lower sustainable growth rate.

As major construction cycles extend over longer periods of time, even with an accelerated construction program, the growth rate of the utility will slow simply because rate base growth will slow and the utility has limited human and capital resources available to expand its construction program. Therefore, the three- to five-year growth rate projection could be used as a long-term sustainable growth rate but not without making a reasonable informed judgment to determine whether it considers the current market environment, the industry, and whether the three- to five-year growth outlook is sustainable.

Q. PLEASE DESCRIBE YOUR MULTI-STAGE GROWTH DCF MODEL.

A. The multi-stage growth DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 through perpetuity.

For the short-term growth period, I relied on the consensus analysts' growth projections described above in the discussion of my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, I assumed each company's growth would converge on the maximum sustainable long-term growth rate.

Q. WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A. Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. Utilities' earnings/dividend growth is created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth. Sales growth, in turn, is tied to economic growth in their service areas.

The U.S. Department of Energy, Energy Information Administration ("EIA") has observed utility sales growth tracks the U.S. GDP growth, albeit at a lower level, as shown in Exhibit AWEC/113. Utility sales growth has lagged behind GDP growth for more than a decade. Therefore, the U.S. GDP nominal growth rate is a conservative (i.e., generous to the utility) proxy for the highest sustainable long-term growth rate of a utility.

Q. IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE GROWTH OF THE U.S. GDP?

A. Yes. This concept is supported in published analyst literature and academic work. Specifically, in a textbook titled "Fundamentals of Financial Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but <u>dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation)</u>.[10/]

The use of the economic growth rate is also supported by investment practitioners as outlined as follows:

> **Estimating Growth Rates**
>
> One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.
>
> * * *
>
> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[11/]

10/ *Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298, emphasis added.

11/ *Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook* at 51 and 52.

Q. IS THERE ANY ACTUAL INVESTMENT HISTORY THAT SUPPORTS THE THEORY THAT THE CAPITAL APPRECIATION FOR STOCK INVESTMENTS WILL NOT EXCEED THE NOMINAL GROWTH OF THE U.S. GDP?

A. Yes. This is evidenced by a comparison of the compound annual growth of the U.S. GDP compared to the geometric growth of the U.S. stock market. Morningstar measures the historical geometric growth of the U.S. stock market over the period 1926-2016 to be approximately 5.8%.[12/] During this same time period, the U.S. nominal compound annual growth of the U.S. GDP was approximately 6.4%.[13/]

As such, the compound geometric growth of the U.S. nominal GDP has been higher but comparable to the nominal growth of the U.S. stock market capital appreciation. This historical relationship indicates the U.S. GDP growth outlook is a conservative estimate of the long-term sustainable growth of U.S. stock investments.

Q. HOW DID YOU DETERMINE A SUSTAINABLE LONG-TERM GROWTH RATE THAT REFLECTS THE CURRENT CONSENSUS OUTLOOK OF THE MARKET?

A. I relied on the consensus analysts' projections of long-term GDP growth. *Blue Chip Economic Indicators* publishes consensus economists' GDP growth projections twice a year. These consensus analysts' GDP growth outlooks are the best available measure of the market's assessment of long-term GDP growth. These analyst projections reflect all current outlooks for GDP and are likely the most influential on investors' expectations of future growth outlooks. The consensus economists' published GDP growth rate outlook is 4.20% over the next five to ten years.[14/]

12/ *Duff & Phelps, 2017 SBBI Yearbook* at 6-17.
13/ U.S. Bureau of Economic Analysis, February 28, 2018.
14/ *Blue Chip Economic Indicators*, March 10, 2018, at 14.

Therefore, I propose to use the consensus economists' projected five- and ten-year average GDP consensus growth rates of 4.20%, as published by *Blue Economic Indicators Forecasts*, as an estimate of long-term sustainable growth. *Blue Chip Economic Indicators* projections provide real GDP growth projections of 2.0% and GDP inflation of 2.1%[15/] over the five-year and ten-year projection periods. These consensus GDP growth forecasts represent the most likely views of market participants because they are based on published consensus economist projections.

Q. DID YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A. Yes, and these sources corroborate my consensus analysts' projections, as shown below in Table 5.

TABLE 5

GDP Forecasts

Source	Term	Real GDP	Inflation	Nominal GDP
Blue Chip Economic Indicators	5-10 Yrs	2.0%	2.1%	4.2%
EIA – Annual Earnings Outlook	28 Yrs	2.0%	2.3%	4.4%
Congressional Budget Office	6 Yrs	1.9%	2.0%	4.0%
Moody's Analytics	25 Yrs	2.0%	1.8%	3.8%
Social Security Administration	49 Yrs			4.4%
The Economist Intelligence Unit	25 Yrs	1.9%	1.8%	3.7%

The EIA, in its *Annual Energy Outlook,* projects real GDP out until 2050. In its 2018 Annual Report, the EIA projects real GDP through 2050 to be 2.0% and a long-term

15/ *Id.*

GDP price inflation projection of 2.3%. The EIA data supports a long-term nominal GDP growth outlook of 4.4%.[16]

Also, the Congressional Budget Office ("CBO") makes long-term economic projections. The CBO is projecting real GDP growth to be 1.9% during the next 6 years with a GDP price inflation outlook of 2.0%. The CBO 6-year outlook for nominal GDP based on this projection is 4.0%.[17]

Moody's Analytics also makes long-term economic projections. In its recent 25-year outlook, Moody's Analytics is projecting real GDP growth of 2.0% with GDP inflation of 1.8%. Based on these projections, Moody's is projecting nominal GDP growth of 3.8% over the next 25 years.[18]

The Social Security Administration ("SSA") makes long-term economic projections out to 2095. The SSA's nominal GDP projection, under its intermediate cost scenario of 49 years, is 4.4%.[19]

The Economist Intelligence Unit, a division of *The Economist* and a third-party data provider to S&P Global Market Intelligence, makes a long-term economic projection out to 2050. The Economist Intelligence Unit is projecting real GDP growth of 1.9% with an inflation rate of 1.8% out to 2050. The real GDP growth projection is in line with the consensus economists. The long-term nominal GDP projection based on these outlooks is approximately 3.7%.[20]

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[16] DOE/EIA Annual Energy Outlook 2018 With Projections to 2050, downloaded March 9, 2018.

[17] *CBO: The Budget and Economic Outlook: 2017 to 2027*, January 2017, downloaded March 1, 2017.

[18] www.economy.com, *Moody's Analytics Forecast*, January 24, 2018.

[19] www.ssa.gov, "2017 OASDI Trustees Report," Table VI.G4, downloaded July 20, 2017.

[20] *S&P Global Market Intelligence, Economist Intelligence Unit*, downloaded on March 14, 2018.

The real GDP and nominal GDP growth projections made by these independent sources support the use of the consensus economists' five-year and ten-year projected GDP growth outlooks as a reasonable estimate of market participants' long-term GDP growth outlooks.

Q. WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE GROWTH DCF ANALYSIS?

A. I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For stage one growth, I used the consensus analysts' growth rate projections discussed above in my constant growth DCF model. The first stage growth covers the first five years, consistent with the term of the analyst growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The second stage growth transitions the growth rate from the first stage to the third stage using a linear trend. For the third stage, or long-term sustainable growth stage, starting in year 11, I used a 4.20% long-term sustainable growth rate based on the consensus economists' long-term projected nominal GDP growth rate.

Q. WHAT ARE THE RESULTS OF YOUR MULTI-STAGE GROWTH DCF MODEL?

A. As shown in Exhibit AWEC/114, the average and median DCF returns on equity for my proxy group using the 13-week average stock price are 7.47% and 7.20%, respectively.

Q. PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A. The results from my DCF analyses are summarized in Table 6 below:

TABLE 6

Summary of DCF Results

Description	Proxy Group Average	Proxy Group Median
Constant Growth DCF Model (Analysts' Growth)	8.94%	8.58%
Constant Growth DCF Model (Sustainable Growth)	11.38%	10.97%
Multi-Stage Growth DCF Model	7.47%	7.20%

I conclude that my DCF studies support a return on equity of 9.0%. I consider the results of all my studies, along with my assessment of the inputs and results as described above. Based on this assessment, I find a return on equity of 9.0% is generally supported by the results of my DCF studies.

III.L. RISK PREMIUM MODEL

Q. PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A. This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be riskier than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds. The difference between the required return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year over the period January 1986 through 2017. The common equity required returns were based on regulatory commission-authorized returns for electric and gas utility companies. Authorized returns are typically based on expert witnesses' estimates of the contemporary investor-required return.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period January 1986 through 2017 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit AWEC/115, which shows the market-to-book ratio since 1986 for the utility industry was consistently above a multiple of 1.0x. Over this period, regulatory authorized returns were sufficient to support market prices that at least exceeded book value. This is an indication that regulatory authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit AWEC/116, the average indicated gas equity risk premium over U.S. Treasury bond yields has been 5.41% for gas. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology.

I incorporated five-year and ten-year rolling average risk premiums over the study period to gauge the variability over time of risk premiums. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. As shown on my Exhibit AWEC/116, the five-year gas rolling average risk premium over Treasury bonds ranged from 4.17% to 6.68%, while the ten-year rolling average risk premium ranged from 4.30% to 6.44%.

As shown on my Exhibit AWEC/117, the average indicated gas equity risk premium over contemporary Moody's utility bond yields was 4.04%. The five-year and ten-year rolling gas average risk premiums ranged from 2.80% to 5.52% and 3.11% to 5.09%, respectively.

Q. DO YOU BELIEVE THAT THE TIME PERIOD USED TO DERIVE THESE EQUITY RISK PREMIUM ESTIMATES IS APPROPRIATE TO FORM AN ACCURATE MEASURE OF CONTEMPORARY MARKET CONDITIONS?

A. Yes. The time period I use in this risk premium study is a generally accepted period to develop a risk premium study using "expectational" data.

Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value is an indication the authorized returns on equity and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

Alternatively, some studies, such as Duff & Phelps referred to later in this testimony, have recommended that use of "actual achieved investment return data" in a risk premium study should be based on long historical time periods. The studies find that achieved returns over short time periods may not reflect investors' expected returns due to unexpected and abnormal stock price performance. Short-term, abnormal actual returns would be smoothed over time and the achieved actual investment returns over long time periods would approximate investors' expected returns. Therefore, it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns.

My risk premium study is based on expectational data, not actual investment returns, and, thus, need not encompass a very long historical time period.

Q. WHAT RISK PREMIUM HAVE YOU USED TO ESTIMATE NW NATURAL'S COST OF COMMON EQUITY IN THIS PROCEEDING?

A. The equity risk premium should reflect the relative market perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit AWEC/118, where I show the yield spread between utility bonds and Treasury bonds over the last 38 years. As shown in this schedule, the average utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.51% and 1.95%, respectively. The utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utilities for 2017 are 1.10% and 1.48%, respectively. The current average "A" rated utility bond yield spread over Treasury bond yields is now lower than the 38-year average spread. The current "Baa" rated utility bond yield spread over Treasury bond yields is also lower than the 38-year average spread.

The current 13-week average "A" rated utility bond yield is 3.99% and compares to the current Treasury bond yield of 3.0%, as shown in Exhibit AWEC/119. This current utility to Treasury bond yield spread of 0.99% is lower than the 38-year average spread for "A" rated utility bonds of 1.51%. The current spread for the "Baa" rated utility bond yield to Treasury bond yield of 1.32% is also lower than the 38-year average spread of 1.95%.

These utility bond yield to Treasury bond yield spreads are evidence that the market perception of utility risk is about average relative to this historical time period and demonstrate that utilities continue to have strong access to capital in the current market.

Q. HOW DID YOU DETERMINE WHAT A REASONABLE RISK PREMIUM IS IN THE CURRENT MARKET?

A. I observed the spread of Treasury securities relative to public utility bonds and corporate bonds in gauging whether or not the risk premium in current market prices is stable relative to the past. What this observation of market evidence clearly demonstrates is that the valuations in the current market place an above average risk premium on securities that have greater risk.

This market evidence is summarized below in Table 7, which shows the utility bond yield spreads over Treasury bond yields on average for the period 1980 through 2017, and the corporate bond yield spreads for Aaa corporates and Baa corporates.

TABLE 7

Comparison of Yield Spreads Over Treasury Bonds

Description	Utility A	Utility Baa	Corporate Aaa	Corporate Baa
Average Historical Spread	1.51%	1.95%	0.84%	1.93%
2016 Spread	1.33%	2.08%	1.07%	2.12%
2017 Spread	1.10%	1.48%	0.85%	1.55%

Source: Exhibit AWEC/118.

The observable yield spreads shown in the table above illustrate that securities of greater risk have recently had average risk premiums relative to the long-term historical average risk premium. Specifically, A-rated utility bonds to Treasuries, a relatively low-risk investment, have a yield spread in 2017 that has been lower than, though comparable to that of, its long-term historical yield spread. This is an indication that low risk investments like A-rated utility bonds have premium values relative to minimal risk Treasury securities.

Only recently have Baa-rated utility bond yield spreads gone below the 38-year average of 1.95%. For example, in 2016, the Baa-rated yield spread averaged 2.08%, which is approximately 13 basis points above the long-term average of 1.95%, shown in Exhibit AWEC/118. While the higher risk Baa utility and corporate bond yields currently have a below-average yield spread of 40 basis points (1.48% vs. 1.95%), there appears to be more volatility in the spread. The higher risk Baa utility bond yields do not have the same premium valuations as their lower risk A-rated utility bond yields, and thus the yield spread for greater risk investments is wider than lower risk investments.

This illustrates that securities with greater risk, such as Baa-rated bonds versus A-rated bonds, have recently commanded above average risk premium spreads in the marketplace. Utility equity securities are greater risk than Baa utility bonds. Because greater risk securities appear to support an above-average risk premium relative to historical averages, this would support an above-average risk premium in measuring a fair return on equity for a utility stock or equity security.

Q. WHAT IS YOUR RECOMMENDED RETURN FOR NW NATURAL BASED ON YOUR RISK PREMIUM STUDY?

A. To be conservative, I am recommending more weight to the high-end risk premium estimates than the low-end. I state this because of the relatively low level of interest rates now but relative upward movements of utility yields more recently. Hence, I propose to provide 70% weight to my high-end risk premium estimates and 30% to the low-end. Applying these weights, the risk premium for Treasury bond yields would be approximately 5.9%,[21/] which is considerably higher than the 32-year average risk premium of 5.41% and reasonably reflective of the 3.7% projected Treasury bond yield. A Treasury bond risk premium of 5.9% and projected Treasury bond yield of 3.7% produce a risk premium estimate of 9.6%.

Similarly, applying these weights to the utility risk premium indicates a risk premium of 4.7%.[22/] This risk premium is above the 32-year historical average risk premium of 4.04%. This risk premium in combination with the current observable Baa

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21/ (4.17% x 30%) + (6.68% x 70%) = 5.9%.
22/ (2.80% x 30%) + (5.52% x 70%) = 4.7%.

utility bond yield of 4.32% produces an estimated return on equity of 9.02%, rounded to 9.0%.

Based on this methodology, my Treasury bond risk premium and my utility bond risk premium indicate a return in the range of 9.00% to 9.60%, with a midpoint of 9.30%.

III.M. CAPITAL ASSET PRICING MODEL ("CAPM")

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

The stock-specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, firm-specific risks can be eliminated by balancing the portfolio with securities that react in the opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix, and production limitations).

The risks that cannot be eliminated when held in a diversified portfolio are non-diversifiable risks. Non-diversifiable risks are related to the market in general and are referred to as systematic risks. Risks that can be eliminated by diversification are non-systematic risks. In a broad sense, systematic risks are market risks and non-systematic risks are business risks. The CAPM theory suggests the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risk investors will be compensated for are systematic or non-diversifiable risks. The beta is a measure of the systematic or non-diversifiable risks.

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A. The CAPM requires an estimate of the market risk-free rate, NW Natural's beta, and the market risk premium.

Q. WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A. Currently, as published in the *Blue Chip Financial Forecasts*, the consensus economists have projected the 30-year Treasury bond yield to be 3.70%.[23/] I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 3.70% for my CAPM analysis.

Q. WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A. Treasury securities are backed by the full faith and credit of the United States government so long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

23/ *Blue Chip Financial Forecasts*, March 1, 2018, at 2.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. A Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic market risks. Consequently, for companies with betas less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q. WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A. As shown in Exhibit AWEC/120, the proxy group average *Value Line* beta estimate is 0.72.

Q. HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATE?

A. I derived two market risk premium estimates: a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

Duff & Phelps' *2017 SBBI Yearbook* estimates the historical arithmetic average inflation-adjusted market return over the period 1926 to 2016 as 8.9%.[24/] A current consensus analysts' inflation projection, as measured by the Consumer Price Index, is 2.30%.[25/] Using these estimates, the expected market return is approximately 11.40%.[26/]

24/ *Duff & Phelps, 2017 SBBI Yearbook* at 6-18.

25/ *Blue Chip Financial Forecasts*, March 1, 2018 at 2.

26/ $\{ [(1 + 0.089) * (1 + 0.023)] - 1 \} * 100$.

The market risk premium then is the difference between the 11.40% expected market return and my 3.70% risk-free rate estimate, or approximately 7.70%.

My historical estimate of the market risk premium was also calculated by using data provided by Duff & Phelps in its *2017 SBBI Yearbook*. Over the period 1926 through 2016, the Duff & Phelps study estimated that the arithmetic average of the achieved total return on the S&P 500 was 12.0%[27/] and the total return on long-term Treasury bonds was 6.0%.[28/] The indicated market risk premium is 6.0% (12.0% - 6.0% = 6.0%).

Q. HOW DOES YOUR ESTIMATED MARKET RISK PREMIUM RANGE COMPARE TO THAT ESTIMATED BY DUFF & PHELPS?

A. The Duff & Phelps analysis indicates a market risk premium falls somewhere in the range of 5.5% to 6.9%. My market risk premium falls in the range of 6.0% to 7.7%. My average market risk premium of approximately 6.9% is at the high-end of the Duff & Phelps range.

Q. HOW DOES DUFF & PHELPS MEASURE A MARKET RISK PREMIUM?

A. Duff & Phelps makes several estimates of a forward-looking market risk premium based on actual achieved data from the historical period of 1926 through 2016 as well as normalized data. Using this data, Duff & Phelps estimates a market risk premium derived from the total return on large company stocks (S&P 500), less the income return on Treasury bonds. The total return includes capital appreciation, dividend or coupon reinvestment returns, and annual yields received from coupons and/or dividend payments. The income return, in contrast, only reflects the income return received from dividend

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27/ *Duff & Phelps, 2017 SBBI Yearbook* at 6-17.

28/ *Id.*

payments or coupon yields. Duff & Phelps claims the income return is the only true risk-free rate associated with Treasury bonds and is the best approximation of a truly risk-free rate.[29/] I disagree with this assessment from Duff & Phelps because it does not reflect a true investment option available to the marketplace and therefore does not produce a legitimate estimate of the expected premium of investing in the stock market versus that of Treasury bonds. Nevertheless, I will use Duff & Phelps' conclusion to show the reasonableness of my market risk premium estimates.

Duff & Phelps' range is based on several methodologies. First, Duff & Phelps estimates a market risk premium of 6.9% based on the difference between the total market return on common stocks (S&P 500) less the income return on Treasury bond investments over the 1926-2016 period.

Second, Duff & Phelps updated the Ibbotson & Chen supply-side model, which found that the 6.9% market risk premium based on the S&P 500 was influenced by an abnormal expansion of price-to-earnings ("P/E") ratios relative to earnings and dividend growth during the period, primarily over the last 30 years. Duff & Phelps believes this abnormal P/E expansion is not sustainable.[30/] Therefore, Duff & Phelps adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings. Based on this alternative methodology, Duff & Phelps published a long-horizon supply-side market risk premium of 5.97%.[31/]

Finally, Duff & Phelps develops its own recommended equity, or market risk premium by employing an analysis that takes into consideration a wide range of

29/ *Duff & Phelps, 2017 Valuation Handbook* at 3-32.
30/ *Id.* at 3-36.
31/ *Id.*

economic information, multiple risk premium estimation methodologies, and the current state of the economy by observing measures such as the level of stock indices and corporate spreads as indicators of perceived risk. Based on this methodology, and utilizing a "normalized" risk-free rate of 3.5%, Duff & Phelps concludes the current expected, or forward-looking, market risk premium is 5.5%, implying an expected return on the market of 9.0%.[32/]

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A. As shown in Exhibit AWEC/121 using the CAPM equation above, based on my prospective market risk premium of 7.7% and my low market risk premium of 6.0%, a risk-free rate of 3.7%, and a beta of 0.72, my CAPM analysis produces return estimates of 9.26% and 8.03%, respectively. Based on my assessment of risk premiums in the market, as discussed above, I will place primary reliance on my high-end CAPM return estimate rounded to 9.30%.

III.N. RETURN ON EQUITY SUMMARY

Q. BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR NW NATURAL?

A. Based on my analyses, I estimate NW Natural's current market cost of equity to be 9.15%.

32/ *Id.* at 3-48.

TABLE 8

Return on Common Equity Summary

Description	Results
DCF	9.00%
Risk Premium	9.30%
CAPM	9.30%

A return on common equity of 9.15% is at the approximate midpoint of my estimated range of 9.00% to 9.30%. As shown in Table 8 above, the high-end of my estimated range is based on my risk premium and CAPM results. The low end of my range is based on my DCF return estimate.

My return on equity estimates reflect observable market evidence, the impact of Federal Reserve policies on current and expected long-term capital market costs, an assessment of the current risk premium built into current market securities, a general assessment of the current investment risk characteristics of the utility industry, and the market's demand for utility securities.

IV. RESPONSE TO NW NATURAL WITNESS DR. BENTE VILLADSEN

Q. WHAT RETURN ON COMMON EQUITY IS NW NATURAL PROPOSING IN THIS PROCEEDING?

A. NW Natural's proposed return on equity is supported by its witness Dr. Bente Villadsen. She recommends a return on equity for NW Natural in the range of 9.7% to 10.3%, with a point estimate of 10.0% (NW Natural/400, Villadsen/3).

Q. PLEASE DESCRIBE DR. VILLADSEN'S METHODOLOGY SUPPORTING HER RETURN ON COMMON EQUITY.

A. Dr. Villadsen arrived at her estimate using several models: a simple DCF, a multi-stage growth DCF, and a risk premium model using a regression formula derived from allowed returns on equity and long-term Treasury yields. Dr. Villadsen relies on a traditional CAPM and an empirical CAPM ("ECAPM") as a check on her results because the Commission has historically not relied upon the CAPM study. These models were applied to a sample of nine gas utility companies, which Dr. Villadsen found had risk comparable to NW Natural. (NW Natural/400, Villadsen/31-33). Dr. Villadsen also developed a subsample, which excludes New Jersey Resources, South Jersey Industries, and WGL Holdings. New Jersey Resources and South Jersey Industries have announced a merger on April 4, 2017. Similarly, WGL was not included in her subsample due to its January 2017 announcement to be acquired by AltaGas. All these companies would have been excluded following Dr. Villadsen's standard screening criteria. However, due to the small size of the sample she only excluded them from the subsample. Also, Dr. Villadsen acknowledged that One Gas has only three years of data and would have been excluded from her proxy group sample but she did not, again due to the small size of the sample. Finally, she noted that Chesapeake was assigned the group average credit rating. (*Id.*).

Q. IS DR. VILLADSEN'S ESTIMATED RETURN ON EQUITY FOR NW NATURAL REASONABLE?

A. No. Dr. Villadsen's recommended return on equity of 10.00% for NW Natural is excessive and unreasonable for a low-risk regulated gas utility company. Further, Dr. Villadsen asserts that considering NW Natural's smaller size, a 20-25 basis points adder is reasonable and warrants a return in the mid to upper end of her range. (NW

Natural/400, Villadsen/2 and Villadsen/46). The unreasonableness of Dr. Villadsen's recommendation is evident from a detailed assessment of the rate of return models supporting her recommendation in this proceeding.

Q. PLEASE SUMMARIZE DR. VILLADSEN'S RETURN ON EQUITY STUDY RESULTS.

A. Dr. Villadsen's return on equity study results are summarized in Table 9 below.

TABLE 9

Summary of Dr. Villadsen's Results

Model	Model Results (1)	ATWACC Adder (2)	Recommended ROE (3)	Adjusted ROE (4)
DCF				
Simple (1/4 Growth)	9.4% - 9.8%	3.1%	12.5% - 12.9%	9.0%
Multi-Stage (Blue Chip)	7.1% - 7.4%	2.0%	9.1% - 9.4%	7.1% - 7.4%
CAPM				
Traditional CAPM	9.1% - 9.3%	1.8% - 2.1%	10.9% - 11.4%	9.1% - 9.3%
ECAPM (1.5%)	9.5% - 9.7%	1.9% - 2.2%	11.4% - 11.9%	8.8%
Traditional CAPM (Hamada)			9.9% - 10.8%	Reject
ECAPM (1.5%) (Hamada)			10.1% - 10.8%	Reject
Risk Premium			10.2% - 10.3%	9.3%
Range			9.7% - 10.3%	8.8% - 9.3%
Requested ROE			10.0%	

ROE = Return on Equity

ATWACC = After-Tax Weighted Average Cost of Capital

As shown in Table 9 above, the model return on equity results of Dr. Villadsen's studies applied to her proxy group indicate that NW Natural's current market return on equity is in the range of 7.1% to 9.8% based on her DCF and CAPM studies, and approximately 10.25% based on her risk premium studies.

She then increases her market return on equity estimate by adding a return on equity adder in the range of 1.8% to 3.1% using an After-Tax Weighted Average Cost of Capital ("ATWACC") adder methodology. This ATWACC adder increases her recommended range up to 9.1% to 12.9%. Dr. Villadsen asserts this ATWACC return on equity adder is necessary to properly recognize NW Natural's financial risk when applying a market return on equity to its book value common equity. (Exhibit NW Natural/400, Villadsen/8). However, Dr. Villadsen acknowledges the excessive returns produced by her ATWACC methodology and narrows her range to eliminate some of the high-end estimates.

Q. DO DR. VILLADSEN'S RETURN ON EQUITY MODEL RESULTS SUPPORT THE COMPANY'S REQUESTED 10.0% RETURN ON EQUITY?

A. No. As described below and as shown in Table 9 above under Column 4, Dr. Villadsen's own studies, adjusted to remove her flawed ATWACC return on equity adder and to incorporate reasonable adjustments, support a return on equity in the range of 8.8% to 9.3% when high and low outliers are removed. These adjusted results are comparable to my recommended return on equity range for NW Natural in this proceeding.

Q. PLEASE DESCRIBE THE ISSUES YOU HAVE WITH DR. VILLADSEN'S ANALYSES.

A. The issues and concerns I have with Dr. Villadsen's analyses in support of the Company's requested return on equity include the following:

1. She includes an ATWACC adjustment to her DCF return estimate.
2. I take issue with her risk premium analysis because it is based only on a simple inverse relationship between equity risk premiums and interest rates. Equity risk

premiums should be measured based on the current market's assessment of investment risk of equity versus debt securities. While interest rate changes are one factor in assessing this risk differential, they are not the only factor. Dr. Villadsen's model is simply misspecified and unreliable.

3. For her CAPM analysis she includes both an ATWACC, and alternatively a leveraged beta adjustment to the results of her CAPM analysis.

4. She also relies on an empirical CAPM analysis and includes adders for ATWACC and leveraged beta adjustments. In addition to my concerns for these two adders, Dr. Villadsen's ECAPM analysis is miscalculated because she uses adjusted betas within an ECAPM format. This is inappropriate because an adjusted beta accomplishes the same thing as an ECAPM analysis. Both levelize the security market line in measuring a fair return on equity based on a given level of systematic risk or beta risk. Her ECAPM analysis double counts the increase in the CAPM return estimates for companies with betas less than 1, which reflects her proxy group and NW Natural in this case.

IV.A. ATWACC

Q. PLEASE DESCRIBE DR. VILLADSEN'S PROPOSED ATWACC RETURN ON EQUITY ADDER.

A. Dr. Villadsen uses the ATWACC to increase the estimated market return on equity based on her DCF and CAPM analyses, to a higher return on equity that can be applied to NW Natural's book value common equity. She does this by calculating the ATWACC using the market return on equity estimate (DCF and CAPM estimates) and market weighted capital structures for each proxy company. She then uses this market ATWACC for each proxy group company and applies NW Natural's capital structure parameters to produce an ATWACC adjusted return for NW Natural.

These ATWACC adjustments to her return on equity estimates are discussed on pages 8-9 of her direct testimony and developed in the workpapers accompanying her exhibits for the DCF and CAPM return estimates.

Q. WHY DOES DR. VILLADSEN BELIEVE THE ATWACC ADJUSTMENT TO HER DCF AND CAPM RETURN ESTIMATES IS REASONABLE?

A. Dr. Villadsen suggests that the sample firms' financial risk is different based on the market value of common equity than is the financial risk based on the book value of common equity. Therefore, Dr. Villadsen proposes to upwardly adjust her DCF and CAPM model results for the difference in financial risk based on the proxy companies' market value of common equity, compared to its book value common equity. (Exhibit NW Natural/400, Villadsen/8-9).

She is in effect suggesting that firms have a different level of financial risk, depending on whether one is observing their market value capital structure or the book value capital structure.

Q. IS THE ATWACC ADJUSTMENT TO THE BASE RETURN ON EQUITY REASONABLE?

A. No. This is flawed for several reasons. First, the Company only has one level of financial risk, not two. Investors do not assess a different amount of financial risk for market and book common equity valuation. Rather, financial risk is a singular risk factor which describes its financial capital structure, cash flow strength to support financial obligations, and default provisions in its financial obligations.

Dr. Villadsen's belief that there are two levels of financial risk is simply not supported. Indeed, it is contradicted by data used by independent market participants to assess investment risk and security valuation. For example, S&P and *Value Line* provide general assessments of the financial and operating (or total investment) risks to the market investors. S&P does this in terms of rating the credit quality of the utility, based on the utility's ability to produce cash flows adequate to meet its book value financial obligations. S&P assesses a company's risk of failing to meet its financial obligations and is a direct assessment of a company's financial risk.

Value Line provides information to the market participants to help them assess the total investment risk including both financial risk and business risk for the utilities and other stock investments. The data *Value Line* provides to investors concerning these investment risk characteristics relates to book value factors including book value capital structure, book value cash flows, and book value earnings. All these book value factors are then used by investors to assess investment risk which allows them to derive market value stock prices. The book value parameters are an integral part of assessing risk and allowing investors to produce market valuations.

There is not a difference in financial risk for a company if you are examining its book value financial risk or market value financial risk. Rather, the book value and market value financial risks for the same company are interconnected to one another, and produce a single level of financial risk for the company.

Q. DO YOU BELIEVE THAT THE ATWACC METHODOLOGY IS REASONABLE POLICY FOR SETTING AN APPROVED RETURN ON EQUITY?

A. No. The ATWACC methodology is poor regulatory policy and should be rejected for several reasons.

1. First, it does not produce clear and transparent objectives for management to use that will accomplish the objective of minimizing its overall rate of return while preserving its financial integrity. Therefore, a regulatory commission cannot oversee the reasonableness and prudence of management decisions in managing its capital structure. Under the ATWACC theory, management's decisions to manage its capital structure can be skewed by changes in market value which change the market value capitalization mix. Management simply has no control over the market value capital structure, but it does have control over the book value capital structure. As such, setting the rate of return and measuring risk based on book value capital structure creates a more transparent and clear path for regulatory oversight of management's effort to maintain a balanced and reasonable capital structure.

2. Second, the ATWACC introduces significant additional instability into the utility's cost of service and tariff rates. Book value capital structure weights permit the utility to hedge or lock-in a large portion of capital market costs in arriving at the rate of return used to set rates. This rate of return cost hedge stabilizes the utility's cost of service, which in turn helps stabilize utility rates. A stable method of setting rates also allows investors to more accurately assess the future earnings and cash flow outlooks for the utility, which will reduce the business risk of the utility. The ATWACC, on the other hand, will produce an overall rate of return which will change based on both changes to market value capital structure weights and also based on changes to market capital costs. Hence, a major component of the cost structure of the utility (i.e., the overall rate of return) will vary based on market forces from rate case to rate case. This rate of return variability will introduce significant instability in the utility's cost of service (via rate of return changes) and hence instability in tariff rates. Introducing additional instability in the utility's cost structure and rates will not benefit either investors or ratepayers.

3. The ATWACC unnecessarily increases rates to produce an excessive return on equity opportunity for utility investors. Inflating utility's rates to provide this excessive earnings opportunity is unjust and unreasonable and should be rejected.

Q. HAS THE ATWACC METHODOLOGY PROPOSED BY DR. VILLADSEN BEEN ACCEPTED IN RATE-SETTING PROCEEDINGS IN THE UNITED STATES?

A. No. The ATWACC methodology has been consistently rejected in state jurisdictions throughout the country. The ATWACC methodology has been rejected by regulators for many reasons:

1. Designed to produce a higher return and no confidence in evidence supporting the ATWACC. (California Public Utilities Commission, Docket No. A.08-05-002, California-American Water Company, May 2009).

2. Method that inflates the rate of return by overstating the Company's financial risk and inflating rates to overcompensate utility investors. The Company simply provided inadequate justification for departing from the traditional method of estimating the rate of return. (Arizona Corporation Commission, Arizona-American Water Company, Docket No. W-01303A-05-0405, July 2006).

3. Is an unproven and never used methodology that is not reliable for setting rates. (Ohio Public Utilities Commission, Cause Nos. 07-551-EL-AIR *et al.*, Ohio Edison Company *et al.*, January 2009).

4. The Commission was not persuaded that the ATWACC methodology was appropriate for setting rates and declined to use it in the rate proceeding. (Public Service Commission of Wisconsin, Wisconsin Electric Power Company, 5-UR-103).

IV.B. Dr. Villadsen's DCF Analyses

Q. PLEASE DESCRIBE DR. VILLADSEN'S DCF ANALYSIS.

A. Dr. Villadsen developed a constant growth DCF model based on a combined growth rate from IBES consensus analysts' and *Value Line*. Dr. Villadsen's DCF model results fall in the range 7.1% and 9.8%, with the higher estimate produced by her simple constant growth DCF model. She applied an ATWACC adder to the DCF model results and increased the DCF range to 9.1% to 12.9%. (Exhibit NW Natural/403, Villadsen/20). However, she acknowledges that the results from the single-stage DCF are substantially higher and she emphasizes the 10% DCF result obtained from the multi-stage model based on the combination of the Blue Chip and OMB growth.

Q. PLEASE DESCRIBE THE ISSUES YOU HAVE WITH DR. VILLADSEN'S DCF ANALYSIS.

A. I have two issues with Dr. Villadsen's DCF analysis. First, as I discussed above, the use of the ATWACC methodology is inappropriate and should be rejected. My second issue deals with interpretation of the central tendency of Dr. Villadsen's DCF study results. For both her full sample and her subsample, the group averages which she relies on are skewed by outlier estimates. This is shown on my Exhibit AWEC/109. As shown on this exhibit, the full proxy group average is 8.9%. However, the median of the group is around 8.6%. The median more accurately represents the central tendency of the entire proxy group. The average is skewed by two high-end outliers for South Jersey Industries and Chesapeake Utilities. While the average of 9.0% is reasonably close to five of the nine proxy group samples, two of the numbers are extreme high-end outliers between 12.5% and 15.8%, while on the low-end the proxy group has two estimates between 7.6% and 7.7%. Hence, I believe the median of the total proxy group more accurately describes the central tendency of the proxy group results. The same is true for her subsample group DCF study. The average of the subsample is 9.4%, but is impacted by Chesapeake Utilities' extreme outlier result. The subset group median result is 9.0%, the same as the full proxy group, and is reasonably consistent with four of the six companies included in the subset. For these reasons, I believe Dr. Villadsen's bare bones DCF study supports a return on equity of 9.0% for NW Natural excluding her flawed ATWACC adder.

IV.C. Dr. Villadsen's Risk Premium Analyses

Q. PLEASE DESCRIBE DR. VILLADSEN'S RISK PREMIUM ANALYSES.

A. As shown on her Exhibit NW Natural/404, Dr. Villadsen measured the relationship of authorized returns on equity to long-term Treasury yields between 1990 and the third quarter of 2017 through a regression analysis. (Exhibit NW Natural/400, Villadsen/41). She then uses the resulting regression formula to predict a risk premium based on a forecasted long-term Treasury yield of 3.94% from October 2017.[33/] This regression formula and her forecasted Treasury yield of 3.94% produced an estimated risk premium of 6.28%, which is approximately 64 basis points higher than the average equity risk premium over the study period of 5.64%. Dr. Villadsen also takes into account the elevated yield spreads and adds an additional 20 basis points to produce a normalized yield of 4.14%, which resulted in an estimated equity risk premium of 6.17%. Finally, Dr. Villadsen adds her estimated risk premiums of 6.28% and 6.17% to the forecasted Treasury yields of 3.94% and 4.14% to produce a cost of equity estimate in the range of 10.2% to 10.3%.

33/ Exhibit NW Natural/400, Villadsen/42.

She also concludes that this estimate does not require adjustment because the regulatory capital structures contain an equity component generally around 50% which is consistent with NW Natural's requested common equity of 50%. (Exhibit NW Natural/400, Villadsen/43).

Q. DO YOU HAVE ANY ISSUES WITH DR. VILLADSEN'S RISK PREMIUM ANALYSIS?

A. Yes. Dr. Villadsen's regression model reflects a simplistic, linear relationship between equity risk premiums and interest rates. This overly simplistic relationship is not based on basic risk and return valuation principles. While academic studies have shown that there has been a positive and negative linear relationship between these variables in the past, these studies have found that the relationship changes over time and is influenced by changes in perception of the investment risk of bond investments relative to equity investments, rather than only changes to nominal interest rates.[34/]

In the 1980s, equity risk premiums were inversely related to interest rates, but that was likely attributable to the interest rate volatility that existed at that time. When interest rates were more volatile, the relative perception of bond investment risk increased relative to the investment risk of equities. This changing investment risk perception caused changes in equity risk premiums.

In today's marketplace, interest rate volatility is not as extreme as it was during the 1980s.[35/] Nevertheless, changes in the perceived risk of bond investments relative to equity investments still drive changes in equity premiums. However, a relative

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[34/] "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," Robert S. Harris and Felicia C. Marston, *Journal of Applied Finance*, Volume 11, No. 1, 2001; "The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management*, Spring 1985.

[35/] Morningstar SBBI, 2009 Classic Yearbook at 95-96.

investment risk differential cannot be measured simply by observing nominal interest rates. Changes in nominal interest rates are highly influenced by changes to inflation outlooks, which also change equity return expectations. As such, the relevant factor needed to explain changes in equity risk premiums is the relative changes to the risk of equity versus debt securities investments, and not simply changes in interest rates.

Importantly, Dr. Villadsen's analysis simply ignores investment risk differentials. She bases her adjustment to the equity risk premium exclusively on changes in nominal interest rates. This is a flawed methodology and does not produce accurate or reliable risk premium estimates. As such, her argument should be rejected by the Commission.

Q. CAN DR. VILLADSEN'S RISK PREMIUM STUDY BE MODIFIED TO PRODUCE A REASONABLE RETURN FOR NW NATURAL?

A. Yes. Disregarding Dr. Villadsen's simplistic inverse relationship and using the current projected Treasury yield published by independent economists, of 3.7%,[36/] and adding this 3.7% Treasury yield to Dr. Villadsen's quarterly average equity risk premium of 5.6% produces a risk premium return on equity for NW Natural of 9.3%.

IV.D. Dr. Villadsen's CAPM Analysis

Q. PLEASE DESCRIBE DR. VILLADSEN'S CAPM ANALYSIS.

A. Dr. Villadsen explains that she only uses the CAPM analyses to corroborate her recommended range and the Company's proposed return on equity. Dr. Villadsen develops two versions of the CAPM model, a traditional CAPM and an Empirical CAPM ("ECAPM).[37/]

36/ *Blue Chip Financial Forecasts*, March 1, 2018 at 2.
37/ Exhibit NW Natural/405.

In her analyses, Dr. Villadsen relied upon two different scenarios. In the first scenario, she used a projected risk-free rate of 4.14% with a market risk premium of 6.94%. In this scenario, Dr. Villadsen increased the risk-free rate by approximately 20 basis points to account for higher interest rates that will align with lower market risk premiums. In the second scenario, she used a risk-free rate of 3.94% with a market risk premium of 7.44%.[38/] Even though Dr. Villadsen applied these two scenarios following her standard procedure, her recommended range is based on the first scenario, which uses the historical market risk premium from the 2017 Duff & Phelps Valuation Handbook. Therefore, my discussion below focuses on the estimates from Scenario 1.

As shown in Table 10 below, based on the scenarios, Dr. Villadsen produced a traditional CAPM before any adders in the range of 9.1% to 9.3% (Column 1, Lines 1 and 5). Similarly, applying the ECAPM before any adders, she produces a return estimate in the range of 9.5% to 9.7% (Column 1, Lines 3 and 7).

38/ *Id*. at 3-4.

TABLE 10

Dr. Villadsen's CAPM Results

Line	Description	Base (1)	Adjusted ROE: ATWACC (2)	Adjusted ROE: Hamada (3)	Adjusted ROE: Tax Hamada (4)	Adders: ATWACC (5)	Adders: Hamada (6)	Adders: Tax Hamada (7)
Full Sample								
	Traditional CAPM							
1	Scenario 1	9.30% [1]	11.40% [3]	10.80% [4]	10.30% [4]	2.10%	1.50%	1.00%
2	Scenario 2	9.50% [2]	11.70% [3]	11.10% [5]	10.60% [5]	2.20%	1.60%	1.10%
	Empirical CAPM							
3	Scenario 1	9.70% [1]	11.90% [3]	10.80% [4]	10.50% [4]	2.20%	1.10%	0.80%
4	Scenario 2	9.90% [2]	12.20% [3]	11.10% [5]	10.70% [5]	2.30%	1.20%	0.80%
Subsample								
	Traditional CAPM							
5	Scenario 1	9.10% [1]	10.90% [3]	10.30% [4]	9.90% [4]	1.80%	1.20%	0.80%
6	Scenario 2	9.20% [2]	11.10% [3]	10.50% [5]	10.10% [5]	1.90%	1.30%	0.90%
	Empirical CAPM							
7	Scenario 1	9.50% [1]	11.40% [3]	10.40% [4]	10.10% [4]	1.90%	0.90%	0.60%
8	Scenario 2	9.70% [2]	11.60% [3]	10.70% [5]	10.40% [5]	1.90%	1.00%	0.70%

Sources:
[1] Exhibit NW Natural/405, Villadsen/3.
[2] Exhibit NW Natural/405, Villadsen/4.
[3] Exhibit NW Natural/405, Villadsen/7.
[4] Exhibit NW Natural/405, Villadsen/10.
[5] Exhibit NW Natural/405, Villadsen/11.

To this barebones or "base" CAPM return, Dr. Villadsen proposes either one of two return on equity adders. First, she proposes to add to her base CAPM return estimate an ATWACC return on equity adder in the range of 190 to 220 basis points. For the reasons outlined above, this ATWACC adder should be rejected as unreliable and an imbalanced return on equity component. Alternatively, Dr. Villadsen proposes a return on equity adder to reflect a leveraged beta adjustment. This leveraged beta adjustment adds 60 to 150 basis points to the base CAPM return.

Dr. Villadsen's leverage adjustment, however, is unreliable and flawed and should be rejected. This leverage adjustment return on equity adder to the base CAPM return estimate produces an excessive and unreasonable return on equity for NW Natural.

Q. PLEASE EXPLAIN DR. VILLADSEN'S LEVERAGED BETA ADJUSTMENT.

A. As an alternative to her ATWACC adder to her CAPM results, Dr. Villadsen also measures an additional return on equity adder based on leveraged adjustments to the beta component of the CAPM study. In producing this adder, she applies the Hamada method for de-levering and re-levering the beta component in both the CAPM and the ECAPM with and without the effect of income taxes. This Hamada beta leveraging adjustment is described by Dr. Villadsen at pages 18-21 of her Exhibit NW Natural/402.

This methodology produces very similar results to Dr. Villadsen's return on equity adder using the ATWACC methodology. Applying the Hamada formula increases the *Value Line* beta from 0.71-0.74 to 0.88-0.96 (without taxes) and 0.83-0.89 (with taxes).[39/] The Hamada model produces CAPM results in the range of 9.9% to 10.8% and ECAPM results in the range of 10.1% to 10.8%.[40/]

Q. IS DR. VILLADSEN'S APPLICATION OF THE LEVERAGED BETA RETURN ON EQUITY ADDER REASONABLE?

A. No. Dr. Villadsen's proposal to de-lever and then re-lever the beta suggests that utilities' financial risk can be measured only by changes in common equity weights of capital structure, and that financial risk is the only relevant systematic risk reflected in beta.

39/ *Id*. at 8-9.
40/ *Id*. at 10.

Neither of these assumptions are accurate. First, a utility company's financial risk is a component of capital structure mix, but also can be impacted by its embedded cost of debt, debt maturity and other liquidity factors. For example, a utility that has lower cost debt and a higher debt percentage of total capital, may have lower financial risk than a utility with a lower debt ratio if its cash flow coverages of interest and total debt are stronger than the latter company. Dr. Villadsen's analysis is not based on a complete assessment of financial risk. Other factors affecting financial risk also relate to cash flow generation relative to financial obligation, and financial instruments' terms and conditions as well as regulatory terms and conditions that support the generation of cash for the utility. All of this is set aside in Dr. Villadsen's financial risk adjustment to beta based on leverage risk alone.

Also, financial risk is not the only systematic risk that should be considered in adjusting beta. Systematic risk can include many factors that were not properly considered by Dr. Villadsen. Applying the Hamada methodology is just another way of increasing the CAPM results. Therefore, Dr. Villadsen's results based on this approach should be completely disregarded by the Commission because they serve only one purpose, to inflate revenue requirements for NW Natural's ratepayers.

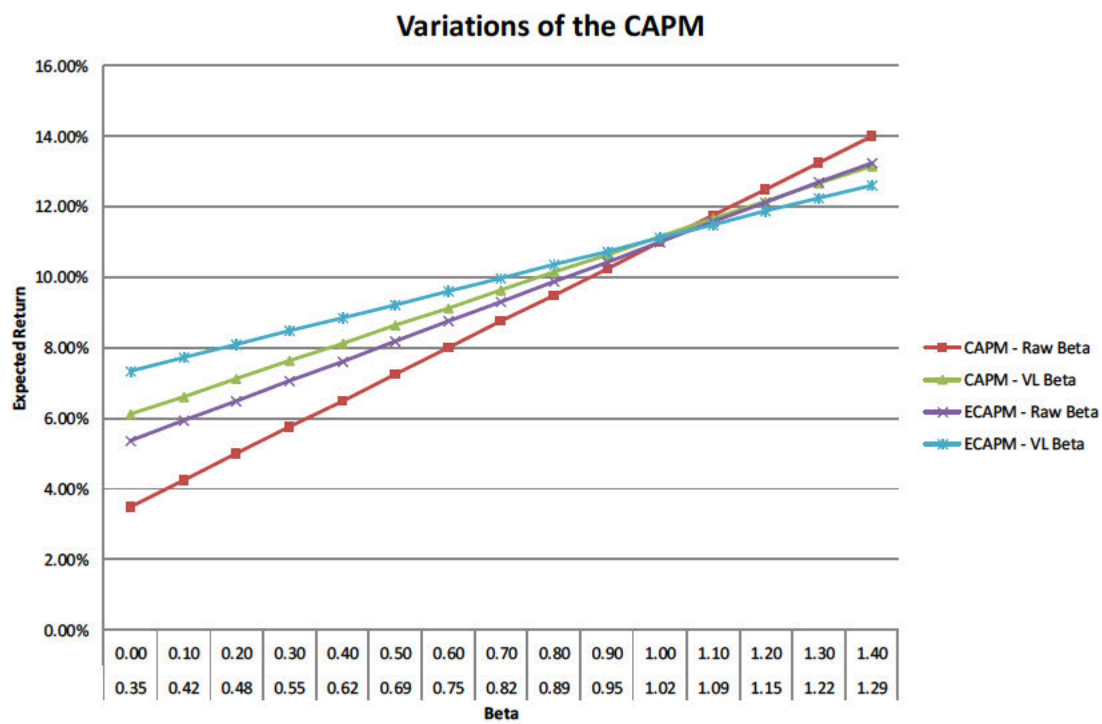
Q. DO YOU HAVE ANY OTHER CONCERNS WITH DR. VILLADSEN'S CAPM RETURN ESTIMATES?

A. Yes. I also have concerns with Dr. Villadsen's development of an ECAPM return estimate. Specifically, Dr. Villadsen included an adjusted beta within her ECAPM study. I believe this is inconsistent with the academic research supporting the development of an

ECAPM methodology.[41/] Bottom line, using adjusted betas within an ECAPM study double counts the purpose of the ECAPM study – that is, to flatten the security market line and increase a CAPM return estimate for companies with betas less than 1, and decrease the CAPM return estimate for betas greater than 1. Dr. Villadsen goes over the objective of the ECAPM at pages 7 and 8 of her Exhibit NW Natural/1103. As shown in Dr. Villadsen's Figure A-2, the ECAPM will raise the intercept point of the security market line and flatten the slope. Again, this has the effect of increasing CAPM return estimates for companies with betas less than 1, and decreasing the CAPM return estimates for companies with betas greater than 1. Importantly, however, the use of an adjusted beta such as those published by *Value Line*, produces comparable adjustments to the security market line and CAPM return estimate. In effect, using an adjusted beta within an ECAPM study has the effect of a double adjustment to the slope and intercept of the security market line. This is illustrated in my Figure 4 below.

[41/] See Black, Fischer, "Beta and Return," *The Journal of Portfolio Management,* Fall 1993, 8-18; and Black, Fischer, Michael C. Jensen and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," 1972.

Figure 4



As shown in Figure 4 above, the CAPM using a *Value Line* beta, versus a CAPM using a raw beta shows that the *Value Line* beta raises the intercept slope and flattens the security market line. Further, the ECAPM using a raw beta, and an ECAPM using a *Value Line* beta, have a magnified effect of increasing the intercept slope and further flattening the security market line.

There is simply no legitimate basis to use an adjusted beta within an ECAPM because they are designed to produce the same effect on the CAPM return estimate.

Q. IS THERE ANY ACADEMIC SUPPORT FOR DR. VILLADSEN'S PROPOSED USE OF AN ADJUSTED BETA IN AN ECAPM STUDY?

A. No. I am unaware of any peer reviewed academic study showing that the ECAPM is more accurate using adjusted betas. To my knowledge, the ECAPM has been tested and published with raw beta estimates. Further, Dr. Villadsen has not provided any academic research that was subjected to academic peer review which supports her proposed use of an adjusted beta in an ECAPM study. As such, the practice of using an adjusted beta in an ECAPM study is simply not supported by academic research. While I have encountered the ECAPM analysis in many proceedings over the last 10 years, I have failed to find any utility witness in support of this methodology that can provide academic support for use of an ECAPM analysis with an adjusted beta such as a *Value Line* published beta. Rather, the ECAPM is designed to accommodate an unadjusted beta. Support for this academic study is identified above. For the reasons outlined above, Dr. Villadsen's proposal to use adjusted betas in an ECAPM study should be rejected.

Q. IS THERE A WAY TO MORE ACCURATELY MEASURE THE COST OF EQUITY FOR NW NATURAL USING THE ECAPM?

A. Because the makeup of the ECAPM model is based on a raw or regression beta, if the appropriate beta is used in the ECAPM it would produce a reasonable return estimate. As such, if the adjusted *Value Line* betas are modified to remove *Value Line*'s adjustment to the regression beta for the long-term tendency to converge on the market beta of 1, the *Value Line* unadjusted beta can be properly used in the ECAPM study.

Removing the beta adjustment to reflect a raw beta for an ECAPM will generally produce a more accurate ECAPM result. For example, on Dr. Villadsen's Exhibit NW Natural/405, page 3, she produces an average CAPM cost for her proxy group of 9.3%, and an ECAPM return of 9.7%. The average proxy group adjusted *Value Line* beta to produce a 9.3% CAPM return is approximately 0.74. This would equate to an unadjusted/raw beta estimate of 0.58.[42/] Using a raw beta of 0.58 and Dr. Villadsen's ECAPM methodology produces an ECAPM estimate of 8.8%.[43/]

Q. DID DR. VILLADSEN ALSO OFFER AN ASSESSMENT OF CURRENT MARKET CONDITIONS IN SUPPORT OF HER RECOMMENDED RETURN ON EQUITY?

A. Yes. Dr. Villadsen suggests a few factors that gauge investor sentiment, including interest rates, credit spreads, investors' perception of market risk premium, and market volatility, measured by the CBOE Volatility Index, known as the VIX.[44/] She concludes that low interest rates resulted in high utility spreads and that market volatility in 2016 has been elevated relative to the volatility observed in the past.

Q. DO YOU BELIEVE THAT DR. VILLADSEN'S USE OF THESE MARKET SENTIMENTS SUPPORTS HER FINDINGS THAT NW NATURAL'S MARKET COST OF EQUITY IS 10.0%?

A. No. In many instances Dr. Villadsen's analysis simply ignores market sentiments favorable toward utility companies and instead lumps utility investments in with higher-risk corporate investments. A fair analysis of utility securities shows the market generally regards utility securities as low-risk investment instruments and supports the finding that utilities' cost of capital is very low in today's marketplace.

Q. WHAT IS THE MARKET SENTIMENT FOR UTILITY INVESTMENTS?

A. The market sentiment toward utility investments, rather than just general corporate investments, is that the market is placing high value on utility securities recognizing their low risk and stable characteristics.

[42/] (Adj. Beta - 0.35)/0.67 = Raw Bea. (0.74 – 0.35)/0.67 = 0.58.

[43/] ECAPM (Raw Beta) = RF + 0.22 x MRP + 0.78 x MRP x Raw Beta.
ECAPM (0.58) = 4.14% + 0.22 x 6.94% + 0.78 x 6.94% x 0.58 = 8.8%.

[44/] Exhibit NW Natural/400, Villadsen/11-28.

This is illustrated by current utility bond yield spreads as discussed at length above. The current strong utility bond valuation is an indication of the market's sentiment that utility bonds are lower risk and are generally regarded as a safe haven by the investment industry.

Further, other measures of utility stock valuations also support a robust market for utility stocks. As shown on my Exhibit AWEC/104, utility valuation measures – *e.g.*, price-to-earnings ratio, market-to-book ratio, and market price to cash flow ratio – show stock valuation measures for the proxy groups are robust. For example, for the proxy group, the current price-to-earnings ratio is comparable to and the cash flow ratio is stronger than the 11-year average valuation metrics.

For all these reasons, direct assessments of valuation measures and market sentiment toward utility securities support the credit rating agencies' findings, as quoted above, that the utility industry is largely regarded as a low-risk, safe haven investment. All of this supports my finding that utilities' market cost of equity is very low in today's very low cost capital market environment.

Q. DO YOU HAVE ANY FURTHER COMMENTS IN REGARD TO DR. VILLADSEN'S INTEREST RATE PROJECTIONS?

A. Yes. First, it is simply not known how much, if any, long-term interest rates will increase from current levels or whether they have already fully accounted for the termination of the Federal Reserve's Quantitative Easing program and the increase in the Federal Funds rate. Nevertheless, I do agree that this Federal Reserve program introduced risk or uncertainty in long-term interest rate markets. Because of this uncertainty, caution should be taken in estimating NW Natural's current return on common equity in this case. However, as noted in the EEI quote above, the increase in short-term interest rates had no impact on longer-term yields that "remain at historically low levels and are influenced more by the level of inflation and economic strength than by the Fed's short-term rate policy."[45]

Second, I would note NW Natural is largely shielded from significant changes in capital market costs. To the extent interest rates ultimately increase above current levels, which may have an impact on required returns on common equity, at that point in time, NW Natural, like all other utilities, can file to change rates to restate its authorized rate of return at the prevailing market levels.

. Finally, while current observable interest rates are actual market data that provides a measure of the current cost of capital, the accuracy of forecasted interest rates is problematic at best.

Q. WHY DO YOU BELIEVE THAT THE ACCURACY OF FORECASTED INTEREST RATES IS HIGHLY PROBLEMATIC?

A. Over the last several years, observable current interest rates have been a more accurate predictor of future interest rates than economists' consensus projections. Exhibit AWEC/122 illustrates this point. On this exhibit, under Columns 1 and 2, I show the actual market yield at the time a projection is made for Treasury bond yields two years in the future. In Column 1, I show the actual Treasury yield. In Column 2, I show the projected yield two years out.

As shown in Columns 1 and 2, over the last several years, Treasury yields were projected to increase relative to the actual Treasury yields at the time of the projection. In Column 4, I show what the Treasury yield actually turned out to be two years after the

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[45] *EEI Q4 2015 Financial Update*: "Stock Performance" at 6.

forecast. In Column 5, I show the actual yield change at the time of the projections relative to the projected yield change.

As shown in this exhibit, economists consistently have been projecting that interest rates will increase over several years. However, as shown in Column 5, those yield projections have turned out to be overstated in almost every case. Indeed, actual Treasury yields have decreased or remained flat over the last several years rather than increased as the economists' projections indicated. As such, current observable interest rates are just as likely, maybe more likely, to accurately predict future interest rates as are current economists' projections.

Q. DID DR. VILLADSEN CONSIDER ADDITIONAL BUSINESS RISKS TO JUSTIFY HER PROPOSED RETURN ON EQUITY?

A. Yes. Dr. Villadsen points out that NW Natural's smaller size, relative to the proxy group, will warrant a return on equity at or above the midpoint of her range.[46/] I disagree. Setting the return on equity as proposed by Dr. Villadsen's model results will place an unreasonable burden on the ratepayers and should be rejected. As discussed below, NW Natural's relative risk is comparable to the risk of the utility companies included in the proxy group.

Q. WHY DO YOU BELIEVE THAT NW NATURAL FACES RISKS THAT ARE COMPARABLE TO THE RISKS FACED BY THE PROXY GROUP COMPANIES?

A. As shown on my Exhibit AWEC/107, the average S&P credit rating for my proxy group of A is lower, albeit comparable to NW Natural's credit rating of A+. On the other hand, the proxy group Moody's credit rating of A3 is identical to NW Natural's credit rating of A3. The relative risks discussed by Dr. Villadsen's testimony are already incorporated in

[46/] Exhibit NW Natural/400, Villadsen/46.

the credit ratings of the proxy group companies. S&P and Moody's go through great detail in assessing a utility's business risk and financial risk in order to evaluate their assessment of its total investment risk. Therefore, this total risk investment assessment of NW Natural, in comparison to a proxy group, is fully absorbed into the market's perception of NW Natural's risk and the proxy group fully captures the investment risk of NW Natural.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 344

In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/101

QUALIFICATIONS OF MICHAEL P. GORMAN

April 20, 2018

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. In 1983 I received a Bachelor of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Arkansas, Arizona, California, Colorado, Delaware, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Louisiana, Michigan, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta and Nova Scotia, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q. PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A. I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 344

In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/102

NW NATURAL PROPOSED CLASS REVENUE ALLOCATION

April 20, 2018

Northwest Natural Gas Company

NW Natural Proposed Class Revenue Allocation

Line	Description	Rate Schedule	Margin Revenue at Present Rates [1] $	Current Class Margin as % of Total Margin (Excluding Spec. Contracts) %	Margin Cost of Service [2] $	Margin Increase Needed for Cost of Service Based Rates $	Margin Increase Needed for Cost of Service Based Rates %	Gas Cost Increase Needed $	Total Revenue Increase Needed $	NW Natural Proposed Increase $	Proposed Increase As % of Current Margin %	Class Increase As % of Total Increase %
			(1)	(2)	(3)	(4) = (3) - (1)	(5) = (4) / (1)	(6)	(7) = (4) + (6)	(8) = (2) * $52,446,470	(9) = (8) / (1)	(10) = (8) / $52,446,470
1	Residential Sales Firm	02	$ 233,911,648	66.84%	$ 296,268,911	$ 62,357,263	26.7%	$ 1,091,161	$ 63,448,424	$ 35,053,997	14.99%	66.84%
2	Commercial Sales Firm	03CSF	71,460,830	20.42%	91,813,231	20,352,401	28.5%	471,721	20,824,122	10,709,119	14.99%	20.42%
3	Industrial Sales Firm	03ISF	1,792,414	0.51%	692,610	(1,099,804)	-61.4%	13,813	(1,085,991)	268,611	14.99%	0.51%
4	Commercial Sales Firm	27CSF	560,310	0.16%	952,115	391,805	69.9%	3,394	395,199	83,968	14.99%	0.16%
5	Commercial Sales Firm	31CSF	8,375,684	2.39%	2,043,959	(6,331,725)	-75.6%	71,951	(6,259,774)	1,255,180	14.99%	2.39%
6	Commercial Transportation Firm	31CTF	1,113,636	0.32%	154,118	(959,518)	-86.2%	-	(959,518)	166,889	14.99%	0.32%
7	Industrial Sales Firm	31ISF	3,215,377	0.92%	1,392,620	(1,822,757)	-56.7%	39,703	(1,783,054)	481,856	14.99%	0.92%
8	Industrial Transportation Firm	31ITF	89,844	0.03%	27,018	(62,826)	-69.9%	-	(62,826)	13,464	14.99%	0.03%
9	Commercial Sales Firm	32CSF	8,944,344	2.56%	1,870,737	(7,073,607)	-79.1%	110,782	(6,962,825)	1,340,399	14.99%	2.56%
10	Industrial Sales Firm	32ISF	2,085,205	0.60%	651,863	(1,433,342)	-68.7%	39,172	(1,394,170)	312,489	14.99%	0.60%
11	Transportation Firm	32TF	7,460,021	2.13%	1,176,029	(6,283,992)	-84.2%	-	(6,283,992)	1,117,959	14.99%	2.13%
12	Commercial Sales Interruptible	32CSI	2,211,377	0.63%	886,831	(1,324,546)	-59.9%	50,073	(1,274,473)	331,397	14.99%	0.63%
13	Industrial Sales Interruptible	32ISI	2,554,521	0.73%	1,441,684	(1,112,837)	-43.6%	57,843	(1,054,994)	382,820	14.99%	0.73%
14	Transportation Interruptible	32TI	6,194,584	1.77%	1,094,929	(5,099,655)	-82.3%	-	(5,099,655)	928,320	14.99%	1.77%
15	Transportation	33T	0	0.00%	0	0	0%	-	-	N/A	N/A	N/A
16	Special Contracts		1,788,868	--	1,788,868	0	0.0%	-	-	N/A	N/A	N/A
17	**Total**		**$ 351,758,663**	**100.00%**	**$ 402,255,523**	**$ 50,496,860**	**14.4%**	**$ 1,949,612**	**$ 52,446,472**	**$ 52,446,470**	**14.91%**	**100.00%**

[1] Exhibit 1101, Line 23
[2] Exhibit 1101, Line 21

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 344

In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/103

AWEC CLASS REVENUE ALLOCATION

April 20, 2018

Northwest Natural Gas Company

AWEC Class Revenue Allocation - Gradual Movement to Cost of Service
(Limit Margin Increase to 1.5x System Average Increase)

Line	Description	Rate Schedule	Margin Revenue at Present Rates [1] $ (1)	Margin Cost of Service [2] $ (2)	Increase Needed for Cost of Service Based Rates $ (3) = (2) - (1)	Increase Needed for Cost of Service Based Rates % (4) = (3) / (1)	Margin Revenue at Proposed Rates $ (5)	Proposed Margin Increase $ (6) = (5) - (1)	Proposed Margin Increase % (7) = (6) / (1)
1	Residential Sales Firm	02	$ 233,911,648	$ 296,268,911	$ 62,357,263	26.7%	$ 284,538,030	$ 50,626,382	21.6%
2	Commercial Sales Firm	03CSF	71,460,830	91,813,231	20,352,401	28.5%	86,927,368	15,466,538	21.6%
3	Industrial Sales Firm	03ISF	1,792,414	692,610	(1,099,804)	-61.4%	1,262,244	(530,170)	-29.6%
4	Commercial Sales Firm	27CSF	560,310	952,115	391,805	69.9%	681,580	121,270	21.6%
5	Commercial Sales Firm	31CSF	8,375,684	2,043,959	(6,331,725)	-75.6%	5,323,422	(3,052,262)	-36.4%
6	Commercial Transportation Firm	31CTF	1,113,636	154,118	(959,518)	-86.2%	651,092	(462,544)	-41.5%
7	Industrial Sales Firm	31ISF	3,215,377	1,392,620	(1,822,757)	-56.7%	2,336,701	(878,676)	-27.3%
8	Industrial Transportation Firm	31ITF	89,844	27,018	(62,826)	-69.9%	59,558	(30,286)	-33.7%
9	Commercial Sales Firm	32CSF	8,944,344	1,870,737	(7,073,607)	-79.1%	5,534,451	(3,409,893)	-38.1%
10	Industrial Sales Firm	32ISF	2,085,205	651,863	(1,433,342)	-68.7%	1,394,250	(690,955)	-33.1%
11	Transportation Firm	32TF	7,460,021	1,176,029	(6,283,992)	-84.2%	4,430,769	(3,029,252)	-40.6%
12	Commercial Sales Interruptible	32CSI	2,211,377	886,831	(1,324,546)	-59.9%	1,572,868	(638,509)	-28.9%
13	Industrial Sales Interruptible	32ISI	2,554,521	1,441,684	(1,112,837)	-43.6%	2,018,068	(536,453)	-21.0%
14	Transportation Interruptible	32TI	6,194,584	1,094,929	(5,099,655)	-82.3%	3,736,252	(2,458,332)	-39.7%
15	Transportation	33T	-	-	-	0.0%	-	-	0.0%
16	Special Contracts		1,788,868	1,788,868	-	0.0%	1,788,868	-	0.0%
17	**Total Distribution Revenues**		**$ 351,758,663**	**$ 402,255,523**	**$ 50,496,860**	**14.4%**	**$ 402,255,523**	**$ 50,496,860**	**14.4%**

[1] Exhibit 1101, Line 23
[2] Exhibit 1101, Line 21

Northwest Natural Gas Company

AWEC Class Revenue Allocation - Recommended Movement to Cost of Service

(Limit Margin Increase to 1.2x System Average Increase; Limit Margin Reduction to 7.5%)

Line	Description	Rate Schedule	Margin Revenue at Present Rates [1] $ (1)	Margin Cost of Service [2] $ (2)	Increase Needed for Cost of Service Based Rates $ (3) = (2) - (1)	Increase Needed for Cost of Service Based Rates % (4) = (3) / (1)	Margin Revenue at Proposed Rates $ (5)	Proposed Margin Increase $ (6) = (5) - (1)	Proposed Margin Increase % (7) = (6) / (1)
1	Residential Sales Firm	02	$ 233,911,648	$ 296,268,911	$ 62,357,263	26.7%	$ 275,046,047	$ 41,134,399	17.6%
2	Commercial Sales Firm	03CSF	71,460,830	91,813,231	20,352,401	28.5%	84,027,533	$ 12,566,703	17.6%
3	Industrial Sales Firm	03ISF	1,792,414	692,610	(1,099,804)	-61.4%	1,657,983	$ (134,431)	-7.5%
4	Commercial Sales Firm	27CSF	560,310	952,115	391,805	69.9%	658,843	$ 98,533	17.6%
5	Commercial Sales Firm	31CSF	8,375,684	2,043,959	(6,331,725)	-75.6%	7,747,508	$ (628,176)	-7.5%
6	Commercial Transportation Firm	31CTF	1,113,636	154,118	(959,518)	-86.2%	1,030,113	$ (83,523)	-7.5%
7	Industrial Sales Firm	31ISF	3,215,377	1,392,620	(1,822,757)	-56.7%	2,974,224	$ (241,153)	-7.5%
8	Industrial Transportation Firm	31ITF	89,844	27,018	(62,826)	-69.9%	83,106	$ (6,738)	-7.5%
9	Commercial Sales Firm	32CSF	8,944,344	1,870,737	(7,073,607)	-79.1%	8,273,518	$ (670,826)	-7.5%
10	Industrial Sales Firm	32ISF	2,085,205	651,863	(1,433,342)	-68.7%	1,928,815	$ (156,390)	-7.5%
11	Transportation Firm	32TF	7,460,021	1,176,029	(6,283,992)	-84.2%	6,900,519	$ (559,502)	-7.5%
12	Commercial Sales Interruptible	32CSI	2,211,377	886,831	(1,324,546)	-59.9%	2,045,524	$ (165,853)	-7.5%
13	Industrial Sales Interruptible	32ISI	2,554,521	1,441,684	(1,112,837)	-43.6%	2,362,932	$ (191,589)	-7.5%
14	Transportation Interruptible	32TI	6,194,584	1,094,929	(5,099,655)	-82.3%	5,729,990	$ (464,594)	-7.5%
15	Transportation	33T	0	0	0	0%	0	$ -	0.0%
16	Special Contracts		1,788,868	1,788,868	0	0%	1,788,868		0.0%
17	**Total Distribution Revenues**		**$ 351,758,663**	**$ 402,255,523**	**$ 50,496,860**	**14.4%**	**$ 402,255,523**	**$ 50,496,860**	**14.4%**

[1] Exhibit 1101, Line 23
[2] Exhibit 1101, Line 21

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 344

In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/104

VALUATION METRICS

April 20, 2018

Northwest Natural Gas Company

Natural Gas Utilities
(Valuation Metrics)

Line	Company	12-Year Average (1)	2017 [2] (2)	2016 (3)	2015 (4)	2014 (5)	2013 (6)	2012 (7)	2011 (8)	2010 (9)	2009 (10)	2008 (11)	2007 (12)	2006 (13)
		Price to Earnings (P/E) Ratio [1]												
1	Atmos Energy	15.94	22.00	20.80	17.50	16.09	15.87	15.93	14.36	13.21	12.54	13.59	15.87	13.52
2	Chesapeake Utilities	17.21	28.20	21.77	19.15	17.70	15.62	14.81	14.16	12.21	14.20	14.15	16.72	17.85
3	New Jersey Resources	16.79	22.40	21.25	16.61	11.73	15.98	16.83	16.76	14.98	14.93	12.27	21.61	16.13
4	NiSource Inc.	19.92	NMF	23.18	37.34	22.74	18.89	17.87	19.36	15.33	14.34	12.07	18.82	19.16
5	Northwest Nat. Gas	19.42	NMF	26.92	23.69	20.69	19.38	21.08	19.02	16.97	15.17	18.08	16.74	15.85
6	ONE Gas Inc.	20.96	23.50	22.74	19.79	17.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	South Jersey Inds.	18.05	27.90	21.71	17.95	18.03	18.90	16.94	18.48	16.81	14.96	15.90	17.18	11.86
8	Southwest Gas	17.30	22.70	21.64	19.35	17.86	15.76	15.00	15.69	13.97	12.20	20.27	17.26	15.94
9	Spire Inc.	16.14	19.80	19.61	16.49	19.80	21.25	14.46	13.05	13.74	13.39	14.31	14.19	13.60
10	UGI Corp.	15.34	20.80	19.33	17.71	15.81	15.44	16.38	15.03	10.86	10.30	13.30	15.14	13.97
11	WGL Holdings Inc.	16.71	25.40	20.05	16.99	15.15	18.25	15.27	16.97	15.11	12.58	13.66	15.60	15.46
12	Average	17.35	23.63	21.73	20.23	17.58	17.53	16.46	16.29	14.32	13.46	14.76	16.91	15.33
13	Median	17.01	22.70	21.64	17.95	17.83	17.11	16.15	16.22	14.48	13.80	13.91	16.73	15.66

Line	Company	12-Year Average (1)	2017 [2/a] (2)	2016 (3)	2015 (4)	2014 (5)	2013 (6)	2012 (7)	2011 (8)	2010 (9)	2009 (10)	2008 (11)	2007 (12)	2006 (13)
		Market Price to Cash Flow (MP/CF) Ratio [1]												
14	Atmos Energy	7.98	12.55	11.36	9.30	8.79	7.72	7.02	6.87	6.15	5.76	6.48	7.44	6.36
15	Chesapeake Utilities	9.29	15.40	12.06	10.16	9.25	8.12	7.46	7.35	6.36	9.48	7.88	8.58	9.40
16	New Jersey Resources	11.85	14.76	13.94	11.71	8.95	11.29	12.29	12.71	11.32	11.34	9.15	13.76	11.01
17	NiSource Inc.	7.70	11.96	8.56	10.38	10.56	8.71	7.81	6.81	5.09	4.06	4.87	6.69	6.87
18	Northwest Nat. Gas	13.33	60.58	11.57	9.46	8.84	8.61	9.48	9.08	8.94	8.26	8.75	8.54	7.83
19	ONE Gas Inc.	10.07	11.84	11.10	9.19	8.16	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	South Jersey Inds.	10.90	13.84	10.88	10.70	10.57	11.57	10.95	11.98	10.78	9.57	10.38	11.23	8.32
21	Southwest Gas	5.89	8.89	7.41	6.56	6.35	5.94	5.55	5.60	4.91	3.84	4.89	5.42	5.28
22	Spire Inc.	9.59	11.10	10.32	8.47	12.03	13.76	8.80	8.08	8.12	8.58	8.95	8.46	8.46
23	UGI Corp.	7.49	10.25	9.02	8.47	7.49	6.55	6.30	7.51	6.02	5.74	7.11	7.92	7.48
24	WGL Holdings Inc.	9.19	13.13	11.36	9.59	8.46	9.83	9.03	9.52	8.34	7.17	7.68	8.39	7.81
25	Average	9.27	16.75	10.69	9.45	9.04	9.21	8.47	8.55	7.60	7.38	7.62	8.64	7.88
26	Median	8.81	12.55	11.10	9.46	8.84	8.66	8.31	7.80	7.24	7.71	7.78	8.42	7.82

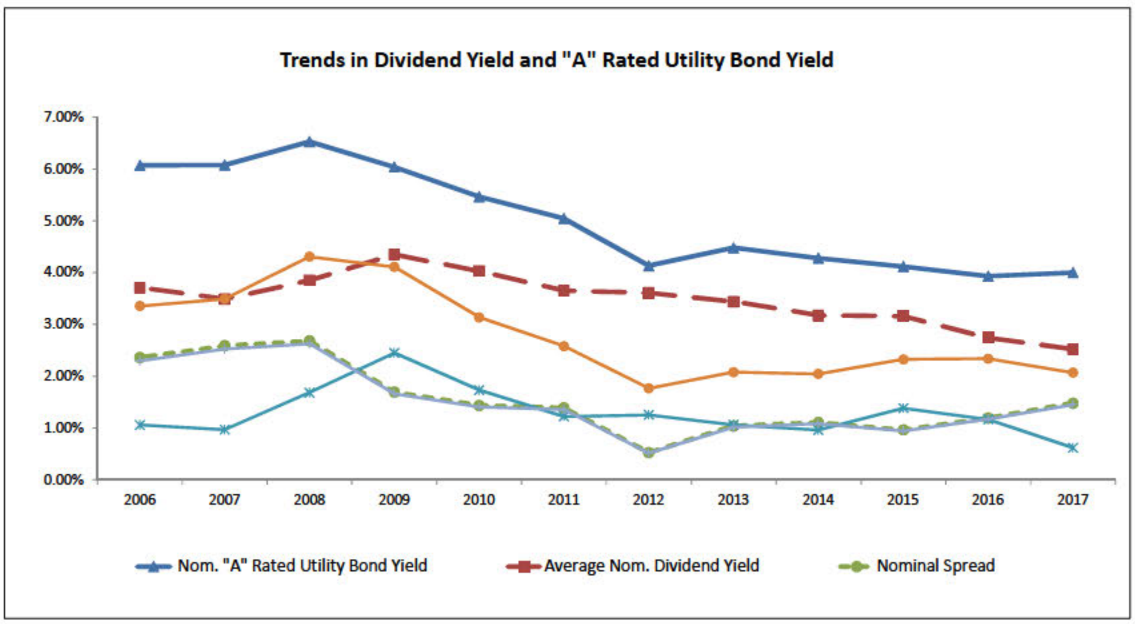
Line	Company	12-Year Average (1)	2017 [2/b] (2)	2016 (3)	2015 (4)	2014 (5)	2013 (6)	2012 (7)	2011 (8)	2010 (9)	2009 (10)	2008 (11)	2007 (12)	2006 (13)
		Market Price to Book Value (MP/BV) Ratio [1]												
27	Atmos Energy	1.48	2.26	2.11	1.72	1.55	1.39	1.28	1.30	1.18	1.05	1.20	1.40	1.34
28	Chesapeake Utilities	1.87	2.61	2.28	2.19	2.12	1.83	1.66	1.61	1.40	1.37	1.64	1.84	1.85
29	New Jersey Resources	2.23	2.76	2.52	2.28	2.13	2.05	2.33	2.31	2.09	2.16	1.92	2.17	2.01
30	NiSource Inc.	1.39	1.93	1.84	1.95	1.94	1.58	1.37	1.15	0.92	0.69	0.94	1.16	1.19
31	Northwest Nat. Gas	1.79	2.11	1.92	1.63	1.59	1.56	1.72	1.70	1.78	1.73	1.96	2.05	1.69
32	ONE Gas Inc.	1.47	1.89	1.67	1.26	1.07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
33	South Jersey Inds.	2.12	2.21	1.79	1.77	2.07	2.27	2.21	2.59	2.38	1.95	2.08	2.21	1.93
34	Southwest Gas	1.53	2.13	1.96	1.68	1.68	1.61	1.51	1.43	1.24	0.97	1.20	1.46	1.46
35	Spire Inc.	1.55	1.76	1.64	1.44	1.33	1.34	1.51	1.46	1.39	1.68	1.71	1.66	1.71
36	UGI Corp.	1.98	2.67	2.41	2.29	1.97	1.69	1.45	1.75	1.55	1.66	2.01	2.16	2.21
37	WGL Holdings Inc.	1.82	2.73	2.45	2.15	1.69	1.71	1.66	1.63	1.50	1.45	1.59	1.64	1.59
38	Average	1.76	2.28	2.05	1.85	1.74	1.70	1.67	1.69	1.54	1.47	1.62	1.78	1.70
39	Median	1.72	2.21	1.96	1.77	1.69	1.65	1.58	1.62	1.45	1.56	1.67	1.75	1.70

Sources:
[1] The Value Line Investment Survey Investment Analyzer Software, downloaded on June 21, 2017.
[2] The Value Line Investment Survey, March 2, 2018.
Notes:
[a] Based on the average of the high and low price for 2017 and the projected 2017 Cash Flow per share, published in The Value Line Investment Survey, March 2, 2018.
[b] Based on the average of the high and low price for 2017 and the projected 2017 Book Value per share, published in The Value Line Investment Survey, March 2, 2018.

Northwest Natural Gas Company

Natural Gas Utilities
(Valuation Metrics)

Line	Company	12-Year Average (1)	2017 [2/a] (2)	2016 (3)	2015 (4)	2014 (5)	2013 (6)	2012 (7)	2011 (8)	2010 (9)	2009 (10)	2008 (11)	2007 (12)	2006 (13)
		Dividend Yield[1]												
1	Atmos Energy	3.84%	2.17%	2.39%	2.88%	3.11%	3.53%	4.13%	4.19%	4.70%	5.34%	4.78%	4.16%	4.66%
2	Chesapeake Utilities	3.10%	1.69%	1.91%	2.18%	2.44%	2.87%	3.25%	3.36%	3.91%	4.09%	4.10%	3.62%	3.76%
3	New Jersey Resources	3.27%	2.63%	2.86%	3.14%	3.50%	3.71%	3.38%	3.33%	3.69%	3.46%	3.35%	3.02%	3.19%
4	NiSource Inc.	4.25%	2.83%	2.76%	3.53%	2.69%	3.30%	3.84%	4.53%	5.66%	7.64%	5.69%	4.29%	4.21%
5	Northwest Nat. Gas	3.65%	2.98%	3.28%	4.01%	4.14%	4.22%	3.83%	3.85%	3.63%	3.73%	3.27%	3.12%	3.73%
6	ONE Gas Inc.	2.42%	2.38%	2.32%	2.71%	2.28%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	South Jersey Inds.	3.23%	3.18%	3.64%	3.95%	3.40%	3.14%	3.22%	2.81%	3.00%	3.43%	3.08%	2.81%	3.15%
8	Southwest Gas	2.87%	2.49%	2.62%	2.87%	2.72%	2.69%	2.75%	2.78%	3.15%	4.01%	3.19%	2.56%	2.60%
9	Spire Inc.	3.92%	2.89%	3.08%	3.53%	3.78%	3.96%	4.11%	4.31%	4.70%	3.91%	3.94%	4.43%	4.34%
10	UGI Corp.	2.89%	1.98%	2.35%	2.50%	2.61%	3.01%	3.68%	3.30%	3.48%	3.23%	2.85%	2.69%	2.96%
11	WGL Holdings Inc.	3.91%	2.52%	2.94%	3.41%	4.24%	3.94%	3.89%	4.06%	4.37%	4.62%	4.22%	4.19%	4.48%
12	**Average**	**3.48%**	**2.52%**	**2.74%**	**3.16%**	**3.17%**	**3.44%**	**3.61%**	**3.65%**	**4.03%**	**4.35%**	**3.85%**	**3.49%**	**3.71%**
13	Median	3.40%	2.52%	2.76%	3.14%	3.11%	3.42%	3.75%	3.60%	3.80%	3.96%	3.65%	3.37%	3.75%
14	Implied Inflation[3]	2.15%	1.89%	1.56%	1.75%	2.19%	2.35%	2.33%	2.40%	2.26%	1.85%	2.13%	2.49%	2.62%
15	**Real Dividend Yield**	**1.30%**	**0.62%**	**1.17%**	**1.38%**	**0.96%**	**1.06%**	**1.25%**	**1.22%**	**1.73%**	**2.45%**	**1.68%**	**0.97%**	**1.06%**
16	**Nominal "A" Rated Utility Bond Yield[4]**	**5.01%**	**4.00%**	**3.93%**	**4.12%**	**4.28%**	**4.48%**	**4.13%**	**5.04%**	**5.46%**	**6.04%**	**6.53%**	**6.07%**	**6.07%**
17	**Real "A" Rated Utility Bond Yield**	**2.80%**	**2.07%**	**2.34%**	**2.33%**	**2.04%**	**2.08%**	**1.76%**	**2.58%**	**3.13%**	**4.11%**	**4.31%**	**3.49%**	**3.36%**
18	**Nominal Spread[b]**	**1.54%**	**1.48%**	**1.19%**	**0.96%**	**1.11%**	**1.04%**	**0.52%**	**1.39%**	**1.43%**	**1.69%**	**2.68%**	**2.59%**	**2.36%**
19	**Real Spread[c]**	**1.50%**	**1.45%**	**1.17%**	**0.94%**	**1.08%**	**1.01%**	**0.51%**	**1.36%**	**1.40%**	**1.66%**	**2.62%**	**2.52%**	**2.30%**



Sources:
[1] The Value Line Investment Survey Investment Analyzer Software, downloaded on June 21, 2017.
[2] The Value Line Investment Survey, March 2, 2018.
[3] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[4] www.moodys.com, Bond Yields and Key Indicators, through December 27, 2017.

Notes:
[a] Based on the average of the high and low price for 2017 and the projected 2017 Dividends Declared per share, published in The Value Line Investment Survey, March 2, 2018.

Northwest Natural Gas Company

Natural Gas Utilities
(Valuation Metrics)

		Dividend per Share[1]												
Line	**Company**	**12-Year Average (1)**	**2017 [2] (2)**	**2016 (3)**	**2015 (4)**	**2014 (5)**	**2013 (6)**	**2012 (7)**	**2011 (8)**	**2010 (9)**	**2009 (10)**	**2008 (11)**	**2007 (12)**	**2006 (13)**
1	Atmos Energy	1.43	1.80	1.68	1.56	1.48	1.40	1.38	1.36	1.34	1.32	1.30	1.28	1.26
2	Chesapeake Utilities	0.97	1.26	1.19	1.12	1.07	1.01	0.96	0.91	0.87	0.83	0.81	0.78	0.77
3	New Jersey Resources	0.75	1.04	0.98	0.93	0.86	0.81	0.77	0.72	0.68	0.62	0.56	0.51	0.48
4	NiSource Inc.	0.89	0.70	0.64	0.83	1.02	0.98	0.94	0.92	0.92	0.92	0.92	0.92	0.92
5	Northwest Nat. Gas	1.71	1.88	1.87	1.86	1.85	1.83	1.79	1.75	1.68	1.60	1.52	1.44	1.39
6	ONE Gas Inc.	1.28	1.68	1.40	1.20	0.84	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	South Jersey Inds.	0.79	1.10	1.06	1.02	0.96	0.90	0.83	0.75	0.68	0.61	0.56	0.51	0.46
8	Southwest Gas	1.25	1.98	1.80	1.62	1.46	1.32	1.18	1.06	1.00	0.95	0.90	0.86	0.82
9	Spire Inc.	1.67	2.10	1.96	1.84	1.76	1.70	1.66	1.61	1.57	1.53	1.49	1.45	1.40
10	UGI Corp.	0.69	0.96	0.93	0.89	0.79	0.74	0.71	0.68	0.60	0.52	0.50	0.48	0.46
11	WGL Holdings Inc.	1.62	2.02	1.93	1.83	1.72	1.66	1.59	1.55	1.50	1.47	1.41	1.37	1.35
12	**Average**	**1.17**	**1.50**	**1.40**	**1.34**	**1.25**	**1.24**	**1.18**	**1.13**	**1.08**	**1.04**	**1.00**	**0.96**	**0.93**
43	**Industry CAGR**	**4.45%**												

Sources:
[1] The Value Line Investment Survey Investment Analyzer Software, downloaded on June 21, 2017.
[2] The Value Line Investment Survey, March 2, 2018.
Notes:
CAGR = Compound Annual Growth Rate

Northwest Natural Gas Company

Natural Gas Utilities
(Valuation Metrics)

		Cash Flow / Capital Spending		
Line	Company	2017 (1)	2018 (2)	3 - 5 yr Projection (3)
1	Atmos Energy	0.59x	0.59x	0.59x
2	Chesapeake Utilities	0.46x	0.50x	0.64x
3	New Jersey Resources	1.19x	1.23x	1.27x
4	NiSource Inc.	0.54x	0.60x	0.62x
5	Northwest Nat. Gas	0.87x	0.80x	0.96x
6	ONE Gas Inc.	0.89x	0.93x	1.12x
7	South Jersey Inds.	0.71x	0.71x	0.63x
8	Southwest Gas	0.84x	0.89x	0.96x
9	Spire Inc.	0.92x	1.00x	1.15x
10	UGI Corp.	1.45x	1.54x	1.66x
11	WGL Holdings Inc.	0.54x	0.57x	0.56x
12	Average	0.82x	0.85x	0.92x
13	Median	0.84x	0.80x	0.96x

Sources:
The Value Line Investment Survey Investment Analyzer Software, downloaded on November 7, 2017.

Notes:
Based on the projected Cash Flow per share and Capital Spending per share.

BEFORE THE PUBLIC UTILITY COMMISSION

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EXHIBIT AWEC/105

AUTHORIZED ROEs

April 20, 2018

Northwest Natural Gas Company

Authorized ROE for Electric Utilities from 2016 to 2018

Line	Year	Company	State (1)	Rate Case Completion Date (2)	Authorized Return on Equity (3)
	2016				
1		Florida Power & Light Company	FL	Nov 29 2016	10.55%
2		Duke Energy Progress, LLC	SC	Dec 7 2016	10.10%
3		Upper Peninsula Power Company	MI	Sep 8 2016	10.00%
4		Wisconsin Power and Light Company	WI	Nov 18 2016	10.00%
5		Liberty Utilities (CalPeco Electric) LLC	CA	Dec 1 2016	10.00%
6		Northern Indiana Public Service Company	IN	Jul 18 2016	9.98%
7		Massachusetts Electric Company	MA	Sep 30 2016	9.90%
8		Virginia Electric and Power Company	NC	Dec 22 2016	9.90%
9		Indianapolis Power & Light Company	IN	Mar 16 2016	9.85%
10		Kingsport Power Company	TN	Aug 9 2016	9.85%
11		Fitchburg Gas and Electric Light Company	MA	Apr 29 2016	9.80%
12		Madison Gas and Electric Company	WI	Nov 9 2016	9.80%
13		Entergy Arkansas, Inc.	AR	Feb 23 2016	9.75%
14		Baltimore Gas and Electric Company	MD	Jun 3 2016	9.75%
15		Atlantic City Electric Company	NJ	Aug 24 2016	9.75%
16		Jersey Central Power & Light Company	NJ	Dec 12 2016	9.60%
17		Sierra Pacific Power Company	NV	Dec 22 2016	9.60%
18		Public Service Company of New Mexico	NM	Sep 28 2016	9.58%
19		Potomac Electric Power Company	MD	Nov 15 2016	9.55%
20		Avista Corporation	WA	Jan 6 2016	9.50%
21		UNS Electric, Inc.	AZ	Aug 18 2016	9.50%
22		PacifiCorp	WA	Sep 1 2016	9.50%
23		Public Service Company of Oklahoma	OK	Nov 10 2016	9.50%
24		Avista Corporation	ID	Dec 28 2016	9.50%
25		El Paso Electric Company	NM	Jun 8 2016	9.48%
26		Black Hills Colorado Electric Utility Company, LP	CO	Dec 19 2016	9.37%
27		United Illuminating Company	CT	Dec 14 2016	9.10%
28		New York State Electric & Gas Corporation	NY	Jun 15 2016	9.00%
29		Rochester Gas and Electric Corporation	NY	Jun 15 2016	9.00%
30		Emera Maine	ME	Dec 19 2016	9.00%
31		Commonwealth Edison Company	IL	Dec 6 2016	8.64%
32		Ameren Illinois Company	IL	Dec 6 2016	8.64%
33		Utilities with an Approved ROE > 9.70%			15
34		Utilities with an Approved ROE ≤ 9.70%			17
35		ROE Range of Utilities with an Approved ROE ≤ 9.70%			8.64% - 9.60%
	2017				
36		Alaska Electric Light and Power Company	AK	Nov 15 2017	11.95%
37		Southern California Edison Company	CA	Oct 26 2017	10.30%
38		Gulf Power Company	FL	Apr 4 2017	10.25%
39		Pacific Gas and Electric Company	CA	Oct 26 2017	10.25%
40		Tampa Electric Company	FL	Nov 6 2017	10.25%
41		San Diego Gas & Electric Co.	CA	Oct 26 2017	10.20%
42		DTE Electric Company	MI	Jan 31 2017	10.10%
43		Consumers Energy Company	MI	Feb 28 2017	10.10%
44		Arizona Public Service Company	AZ	Aug 15 2017	10.00%
45		NSTAR Electric Company	MA	Nov 30 2017	10.00%
46		Western Massachusetts Electric Company	MA	Nov 30 2017	10.00%
47		Oncor Electric Delivery Company LLC	TX	Sep 28 2017	9.80%
48		Northern States Power Company - WI	WI	Dec 7 2017	9.80%
49		Tucson Electric Power Company	AZ	Feb 24 2017	9.75%
50		Delmarva Power & Light Company	DE	May 23 2017	9.70%
51		Kentucky Utilities Company	KY	Jun 22 2017	9.70%
52		Louisville Gas and Electric Company	KY	Jun 22 2017	9.70%
53		MDU Resources Group, Inc.	ND	Jun 16 2017	9.65%
54		El Paso Electric Company	TX	Dec 14 2017	9.65%
55		Electric Transmission Texas, LLC	TX	Jan 12 2017	9.60%
56		Delmarva Power & Light Company	MD	Feb 15 2017	9.60%
57		Rockland Electric Company	NJ	Feb 22 2017	9.60%
58		Atlantic City Electric Company	NJ	Sep 22 2017	9.60%
59		Southwestern Electric Power Company	TX	Dec 14 2017	9.60%
60		Public Service Company of New Mexico	NM	Dec 20 2017	9.58%
61		Oklahoma Gas and Electric Company	OK	Mar 20 2017	9.50%
62		Unitil Energy Systems, Inc.	NH	Apr 20 2017	9.50%
63		Kansas City Power & Light Company	MO	May 3 2017	9.50%
64		Oklahoma Gas and Electric Company	AR	May 18 2017	9.50%
65		Potomac Electric Power Company	DC	Jul 24 2017	9.50%
66		Potomac Electric Power Company	MD	Oct 20 2017	9.50%
67		Puget Sound Energy, Inc.	WA	Dec 5 2017	9.50%
68		Portland General Electric Company	OR	Dec 18 2017	9.50%
69		Avista Corporation	ID	Dec 28 2017	9.50%
70		MDU Resources Group, Inc.	WY	Jan 18 2017	9.45%
71		Otter Tail Power Company	MN	Mar 2 2017	9.41%
72		Liberty Utilities (Granite State Electric) Corp.	NH	Apr 12 2017	9.40%
73		Nevada Power Company	NV	Dec 29 2017	9.40%
74		Northern States Power Company - MN	MN	May 11 2017	9.20%
75		Green Mountain Power Corporation	VT	Dec 21 2017	9.10%
76		Consolidated Edison Company of New York, Inc.	NY	Jan 24 2017	9.00%
77		Commonwealth Edison Company	IL	Dec 6 2017	8.40%
78		Ameren Illinois Company	IL	Dec 6 2017	8.40%
79		Utilities with an Approved ROE > 9.70%			14
80		Utilities with an Approved ROE ≤ 9.70%			29
81		ROE Range of Utilities with an Approved ROE ≤ 9.70%			9.40% - 9.70%
	2018				
82		Duke Energy Progress, LLC	NC	Feb 23 2018	9.90%
83		Kentucky Power Company	KY	Jan 18 2018	9.70%
84		Interstate Power and Light Company	IA	Feb 2 2018	9.60%
85		Public Service Company of Oklahoma	OK	Jan 31 2018	9.30%
86		ALLETE (Minnesota Power)	MN	Mar 12 2018	9.25%
87		Niagara Mohawk Power Corporation	NY	Mar 15 2018	9.00%
88		Utilities with an Approved ROE > 9.70%			1
89		Utilities with an Approved ROE ≤ 9.70%			5
90		ROE Range of Utilities with an Approved ROE ≤ 9.70%			9.00% - 9.90%

Source and Note:
S&P Global Market Intelligence.
2018 data through March 19, 2018.

Northwest Natural Gas Company

Authorized ROE for Vertically Integrated Electric Cases from 2016 to 2018

Line	Year	Company	State	Rate Case Completion Date	Authorized Return on Equity
			(1)	(2)	(3)
	2016				
1		Florida Power & Light Company	FL	Nov 29 2016	10.55%
2		Duke Energy Progress, LLC	SC	Dec 7 2016	10.10%
3		Upper Peninsula Power Company	MI	Sep 8 2016	10.00%
4		Wisconsin Power and Light Company	WI	Nov 18 2016	10.00%
5		Liberty Utilities (CalPeco Electric) LLC	CA	Dec 1 2016	10.00%
6		Northern Indiana Public Service Company	IN	Jul 18 2016	9.98%
7		Virginia Electric and Power Company	NC	Dec 22 2016	9.90%
8		Indianapolis Power & Light Company	IN	Mar 16 2016	9.85%
9		Kingsport Power Company	TN	Aug 9 2016	9.85%
10		Madison Gas and Electric Company	WI	Nov 9 2016	9.80%
11		Entergy Arkansas, Inc.	AR	Feb 23 2016	9.75%
12		Sierra Pacific Power Company	NV	Dec 22 2016	9.60%
13		Public Service Company of New Mexico	NM	Sep 28 2016	9.58%
14		Avista Corporation	WA	Jan 6 2016	9.50%
15		UNS Electric, Inc.	AZ	Aug 18 2016	9.50%
16		PacifiCorp	WA	Sep 1 2016	9.50%
17		Public Service Company of Oklahoma	OK	Nov 10 2016	9.50%
18		Avista Corporation	ID	Dec 28 2016	9.50%
19		El Paso Electric Company	NM	Jun 8 2016	9.48%
20		Black Hills Colorado Electric Utility Company, LP	CO	Dec 19 2016	9.37%
21		Utilities with an Approved ROE > 9.70%			11
22		Utilities with an Approved ROE ≤ 9.70%			9
23		ROE Range of Utilities with an Approved ROE ≤ 9.70%			9.37% - 9.60%
	2017				
24		Alaska Electric Light and Power Company	AK	Nov 15 2017	11.95%
25		Southern California Edison Company	CA	Oct 26 2017	10.30%
26		Gulf Power Company	FL	Apr 4 2017	10.25%
27		Pacific Gas and Electric Company	CA	Oct 26 2017	10.25%
28		Tampa Electric Company	FL	Nov 6 2017	10.25%
29		San Diego Gas & Electric Co.	CA	Oct 26 2017	10.20%
30		DTE Electric Company	MI	Jan 31 2017	10.10%
31		Consumers Energy Company	MI	Feb 28 2017	10.10%
32		Arizona Public Service Company	AZ	Aug 15 2017	10.00%
33		Northern States Power Company - WI	WI	Dec 7 2017	9.80%
34		Tucson Electric Power Company	AZ	Feb 24 2017	9.75%
35		Kentucky Utilities Company	KY	Jun 22 2017	9.70%
36		Louisville Gas and Electric Company	KY	Jun 22 2017	9.70%
37		MDU Resources Group, Inc.	ND	Jun 16 2017	9.65%
38		El Paso Electric Company	TX	Dec 14 2017	9.65%
39		Southwestern Electric Power Company	TX	Dec 14 2017	9.60%
40		Public Service Company of New Mexico	NM	Dec 20 2017	9.58%
41		Oklahoma Gas and Electric Company	OK	Mar 20 2017	9.50%
42		Kansas City Power & Light Company	MO	May 3 2017	9.50%
43		Oklahoma Gas and Electric Company	AR	May 18 2017	9.50%
44		Puget Sound Energy, Inc.	WA	Dec 5 2017	9.50%
45		Portland General Electric Company	OR	Dec 18 2017	9.50%
46		Avista Corporation	ID	Dec 28 2017	9.50%
47		MDU Resources Group, Inc.	WY	Jan 18 2017	9.45%
48		Otter Tail Power Company	MN	Mar 2 2017	9.41%
49		Nevada Power Company	NV	Dec 29 2017	9.40%
50		Northern States Power Company - MN	MN	May 11 2017	9.20%
51		Green Mountain Power Corporation	VT	Dec 21 2017	9.10%
52		Utilities with an Approved ROE > 9.70%			11
53		Utilities with an Approved ROE ≤ 9.70%			17
54		ROE Range of Utilities with an Approved ROE ≤ 9.70%			9.10% - 9.70%
	2018				
55		Duke Energy Progress, LLC	NC	Feb 23 2018	9.90%
56		Kentucky Power Company	KY	Jan 18 2018	9.70%
57		Interstate Power and Light Company	IA	Feb 2 2018	9.60%
58		Public Service Company of Oklahoma	OK	Jan 31 2018	9.30%
59		ALLETE (Minnesota Power)	MN	Mar 12 2018	9.25%
60		Utilities with an Approved ROE > 9.70%			1
61		Utilities with an Approved ROE ≤ 9.70%			4
52		ROE Range of Utilities with an Approved ROE ≤ 9.70%			9.25% - 9.70%

Source and Note:
S&P Global Market Intelligence.
2018 data through March 19, 2018.

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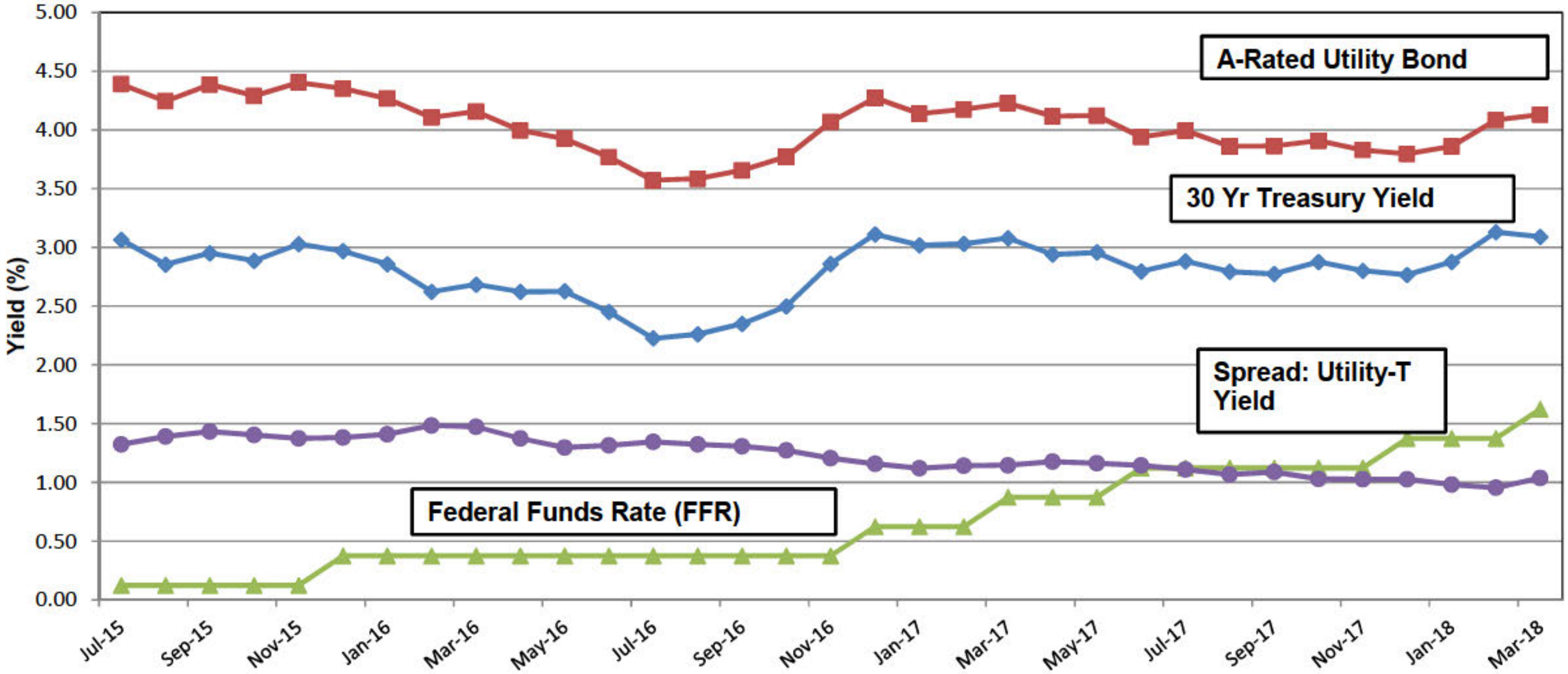
EXHIBIT AWEC/106

TIMELINE OF FEDERAL FUNDS RATE INCREASES

April 20, 2018

Northwest Natural Gas Company

Timeline of Federal Funds Rate Increases



Fed FFR Actions:

December 2015	0.25	→	0.50
December 2016	0.50	→	0.75
March 2017	0.75	→	1.00
June 2017	1.00	→	1.25
December 2017	1.25	→	1.50
March 2018	1.50	→	1.75

Sources:
Federal Reserve Bank of New York, https://apps.newyorkfed.org/markets/autorates/fed-funds-search-page
Board of Governors of the Federal Reserve System, https://www.federalreserve.gov/datadownload/
Moody's Credit Trends, https://credittrends.moodys.com/

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EXHIBIT AWEC/107

PROXY GROUP

April 20, 2018

Northwest Natural Gas Company

Proxy Group

Line	Company	Credit Ratings[1] S&P (1)	Credit Ratings[1] Moody's (2)	Common Equity Ratios MI[1] (3)	Common Equity Ratios Value Line[2] (4)
1	Atmos Energy Corporation	A	A2	52.6%	56.0%
2	Chesapeake Utilities Corporation	N/A	N/A	51.5%	70.0%
3	New Jersey Resources Corporation [3]	A	Aa2	46.4%	55.4%
4	Northwest Natural Gas Company	A+	A3	47.1%	47.2%
5	ONE Gas, Inc.	A	A2	55.8%	62.0%
6	South Jersey Industries, Inc.	BBB+	N/A	43.7%	51.0%
7	Southwest Gas Holdings, Inc.	BBB+	Baa1	47.1%	50.5%
8	Spire Inc.	A-	Baa2	43.6%	50.0%
9	WGL Holdings, Inc.	A	A3	39.8%	50.7%
10	**Average**	**A**	**A3**	**47.5%**	**54.8%**
11	**Northwest Natural Gas Company**	**A+**[4]	**A3**[4]		**50%**[5]

Sources:

[1] S&P Global Market Intelligence, Downloaded on March 19, 2018.

[2] *The Value Line Investment Survey* , March 2, 2018.

[3] New Jersery Resoruces Corp. has no credit ratings, so the ratings of its wholly owned subsidiary, New Jersey Natural Gas Co. are used.

[4] Villadsen direct at 4.

[5] Burkhartsmeyer direct at 3.

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EXHIBIT AWEC/108

CONSENSUS ANALYSTS' GROWTH RATES

April 20, 2018

Northwest Natural Gas Company

Consensus Analysts' Growth Rates

		Zacks		MI		Reuters		Average of
Line	Company	Estimated Growth %[1]	Number of Estimates	Estimated Growth %[2]	Number of Estimates	Estimated Growth %[3]	Number of Estimates	Growth Rates
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Atmos Energy Corporation	7.00%	N/A	7.00%	1	7.15%	2	7.05%
2	Chesapeake Utilities Corporation	6.00%	N/A	8.00%	2	6.00%	1	6.67%
3	New Jersey Resources Corporation	6.00%	N/A	7.00%	2	6.00%	2	6.33%
4	Northwest Natural Gas Company	4.00%	N/A	4.33%	2	4.00%	2	4.11%
5	ONE Gas, Inc.	5.60%	N/A	5.00%	2	5.50%	2	5.37%
6	South Jersey Industries, Inc.	10.00%	N/A	7.50%	2	N/A	N/A	8.75%
7	Southwest Gas Holdings, Inc.	N/A	N/A	4.00%	1	N/A	N/A	4.00%
8	Spire Inc.	4.50%	N/A	6.00%	1	4.43%	3	4.98%
9	WGL Holdings, Inc.	6.00%	N/A	7.00%	1	N/A	N/A	6.50%
10	**Average**	**6.14%**	**N/A**	**6.20%**	**2**	**5.51%**	**2**	**5.97%**

Sources:
[1] Zacks Elite, http://www.zackselite.com/, downloaded on March 16, 2018.
[2] S&P Global Market Intelligence, https://platform.mi.spglobal.com, downloaded on March 16, 2018.
[3] Reuters, http://www.reuters.com/, downloaded on March 16, 2018.

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EXHIBIT AWEC/109

CONSTANT GROWTH DCF MODEL
(CONSENSUS ANALYSTS' GROWTH RATES)

April 20, 2018

Northwest Natural Gas Company

Constant Growth DCF Model
(Consensus Analysts' Growth Rates)

Line	Company	13-Week AVG Stock Price[1] (1)	Analysts' Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	Atmos Energy Corporation	$82.19	7.05%	$1.94	2.53%	9.58%
2	Chesapeake Utilities Corporation	$72.35	6.67%	$1.30	1.92%	8.58%
3	New Jersey Resources Corporation	$39.08	6.33%	$1.09	2.97%	9.30%
4	Northwest Natural Gas Company	$56.89	4.11%	$1.89	3.46%	7.57%
5	ONE Gas, Inc.	$68.64	5.37%	$1.84	2.82%	8.19%
6	South Jersey Industries, Inc.	$28.87	8.75%	$1.11	4.17%	12.92%
7	Southwest Gas Holdings, Inc.	$73.25	4.00%	$1.98	2.81%	6.81%
8	Spire Inc.	$69.07	4.98%	$2.25	3.42%	8.40%
9	WGL Holdings, Inc.	$84.41	6.50%	$2.04	2.57%	9.07%
10	**Average**	**$63.86**	**5.97%**	**$1.72**	**2.96%**	**8.94%**
11	**Median**					**8.58%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on March 19, 2018.
[2] AWEC/108.
[3] *The Value Line Investment Survey* , March 2, 2018.

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EXHIBIT AWEC/110

PAYOUT RATIOS

April 20, 2018

Northwest Natural Gas Company

Payout Ratios

Line	Company	Dividends Per Share 2017 (1)	Dividends Per Share Projected (2)	Earnings Per Share 2017 (3)	Earnings Per Share Projected (4)	Payout Ratio 2017 (5)	Payout Ratio Projected (6)
1	Atmos Energy Corporation	$1.80	$2.50	$3.60	$5.15	50.00%	48.54%
2	Chesapeake Utilities Corporation	$1.26	$1.60	$2.65	$4.20	47.55%	38.10%
3	New Jersey Resources Corporation	$1.04	$1.24	$1.73	$2.95	60.12%	42.03%
4	Northwest Natural Gas Company	$1.88	$2.20	-$1.94	$3.50		
5	ONE Gas, Inc.	$1.68	$2.50	$3.02	$4.00	55.63%	62.50%
6	South Jersey Industries, Inc.	$1.10	$1.35	$1.23	$2.25	89.43%	60.00%
7	Southwest Gas Holdings, Inc.	$1.98	$2.60	$3.55	$5.10	55.77%	50.98%
8	Spire Inc.	$2.10	$2.50	$3.43	$5.50	61.22%	45.45%
9	WGL Holdings, Inc.	$2.02	$2.24	$3.11	$4.60	64.95%	48.70%
10	**Average**	**$1.65**	**$2.08**	**$2.26**	**$4.14**	**60.58%**	**49.54%**

Source:
The Value Line Investment Survey , March 2, 2018.

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EXHIBIT AWEC/111

SUSTAINABLE GROWTH RATE

April 20, 2018

Northwest Natural Gas Company

Sustainable Growth Rate

Line	Company	Dividends Per Share (1)	Earnings Per Share (2)	Book Value Per Share (3)	Book Value Growth (4)	ROE (5)	Adjustment Factor (6)	Adjusted ROE (7)	Payout Ratio (8)	Retention Rate (9)	Internal Growth Rate (10)	Sustainable Growth Rate (11)
		3 to 5 Year Projections										
1	Atmos Energy Corporation	$2.50	$5.15	$46.55	4.85%	11.06%	1.02	11.33%	48.54%	51.46%	5.83%	10.96%
2	Chesapeake Utilities Corporation	$1.60	$4.20	$36.75	5.11%	11.43%	1.02	11.71%	38.10%	61.90%	7.25%	13.23%
3	New Jersey Resources Corporation	$1.24	$2.95	$22.70	9.64%	13.00%	1.05	13.59%	42.03%	57.97%	7.88%	7.95%
4	Northwest Natural Gas Company	$2.20	$3.50	$30.85	0.63%	11.35%	1.00	11.38%	0.00%	100.00%	11.38%	12.17%
5	ONE Gas, Inc.	$2.50	$4.00	$43.40	3.13%	9.22%	1.02	9.36%	62.50%	37.50%	3.51%	4.30%
6	South Jersey Industries, Inc.	$1.35	$2.25	$20.00	5.03%	11.25%	1.02	11.53%	60.00%	40.00%	4.61%	5.64%
7	Southwest Gas Holdings, Inc.	$2.60	$5.10	$58.50	9.42%	8.72%	1.04	9.11%	50.98%	49.02%	4.47%	6.39%
8	Spire Inc.	$2.50	$5.50	$53.50	5.33%	10.28%	1.03	10.55%	45.45%	54.55%	5.75%	6.23%
9	WGL Holdings, Inc.	$2.24	$4.60	$43.10	7.99%	10.67%	1.04	11.08%	48.70%	51.30%	5.69%	8.38%
10	**Average**	**$2.08**	**$4.14**	**$39.48**	**5.68%**	**10.77%**	**1.03**	**11.07%**	**44.03%**	**55.97%**	**6.26%**	**8.36%**

Sources and Notes:
Cols. (1), (2) and (3): *The Value Line Investment Survey* , March 2, 2018.
Col. (4): [Col. (3) / Page 2 Col. (2)] ^ (1/number of years projected) - 1.
Col. (5): Col. (2) / Col. (3).
Col. (6): [2 * (1 + Col. (4))] / (2 + Col. (4)).
Col. (7): Col. (6) * Col. (5).
Col. (8): Col. (1) / Col. (2).
Col. (9): 1 - Col. (8).
Col. (10): Col. (9) * Col. (7).
Col. (11): Col. (10) + Page 2 Col. (9).

Northwest Natural Gas Company

Sustainable Growth Rate

Line	Company	13-Week Average Stock Price[1] (1)	2017 Book Value Per Share[2] (2)	Market to Book Ratio (3)	Common Shares Outstanding (in Millions)[2] 2017 (4)	Common Shares Outstanding (in Millions)[2] 3-5 Years (5)	Growth (6)	S Factor[3] (7)	V Factor[4] (8)	S * V (9)
1	Atmos Energy Corporation	$82.19	$36.74	2.24	106.10	130.00	4.15%	9.28%	55.30%	5.13%
2	Chesapeake Utilities Corporation	$72.35	$28.65	2.53	16.50	20.00	3.92%	9.91%	60.40%	5.98%
3	New Jersey Resources Corporation	$39.08	$14.33	2.73	86.32	86.50	0.04%	0.11%	63.33%	0.07%
4	Northwest Natural Gas Company	$56.89	$29.90	1.90	28.73	30.00	0.87%	1.65%	47.44%	0.78%
5	ONE Gas, Inc.	$68.64	$37.20	1.85	52.50	55.00	0.93%	1.72%	45.81%	0.79%
6	South Jersey Industries, Inc.	$28.87	$15.65	1.84	80.00	85.00	1.22%	2.25%	45.79%	1.03%
7	Southwest Gas Holdings, Inc.	$73.25	$37.30	1.96	48.00	53.00	2.00%	3.93%	49.08%	1.93%
8	Spire Inc.	$69.07	$41.26	1.67	48.26	50.00	0.71%	1.19%	40.26%	0.48%
9	WGL Holdings, Inc.	$84.41	$29.35	2.88	51.21	55.00	1.44%	4.14%	65.23%	2.70%
10	**Average**	**$63.86**	**$30.04**	**2.18**	**57.51**	**62.72**	**1.70%**	**3.80%**	**52.52%**	**2.10%**

Sources and Notes:
[1] S&P Global Market Intelligence, Downloaded on March 19, 2018.
[2] *The Value Line Investment Survey* , March 2, 2018.
[3] Expected Growth in the Number of Shares, Column (3) * Column (6).
[4] Expected Profit of Stock Investment, [1 - 1 / Column (3)].

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 344

In the Matter of	)
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EXHIBIT AWEC/112

CONSTANT GROWTH DCF MODEL
(SUSTAINABLE GROWTH RATE)

April 20, 2018

Northwest Natural Gas Company

Constant Growth DCF Model
(Sustainable Growth Rate)

Line	Company	13-Week AVG Stock Price[1] (1)	Sustainable Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	Atmos Energy Corporation	$82.19	10.96%	$1.94	2.62%	13.58%
2	Chesapeake Utilities Corporation	$72.35	13.23%	$1.30	2.03%	15.27%
3	New Jersey Resources Corporation	$39.08	7.95%	$1.09	3.02%	10.97%
4	Northwest Natural Gas Company	$56.89	12.17%	$1.89	3.73%	15.89%
5	ONE Gas, Inc.	$68.64	4.30%	$1.84	2.80%	7.10%
6	South Jersey Industries, Inc.	$28.87	5.64%	$1.11	4.05%	9.69%
7	Southwest Gas Holdings, Inc.	$73.25	6.39%	$1.98	2.88%	9.27%
8	Spire Inc.	$69.07	6.23%	$2.25	3.46%	9.69%
9	WGL Holdings, Inc.	$84.41	8.38%	$2.04	2.62%	11.00%
10	**Average**	**$63.86**	**8.36%**	**$1.72**	**3.02%**	**11.38%**
11	**Median**					**10.97%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on March 19, 2018.
[2] AWEC/111, page 1.
[3] *The Value Line Investment Survey*, March 2, 2018.

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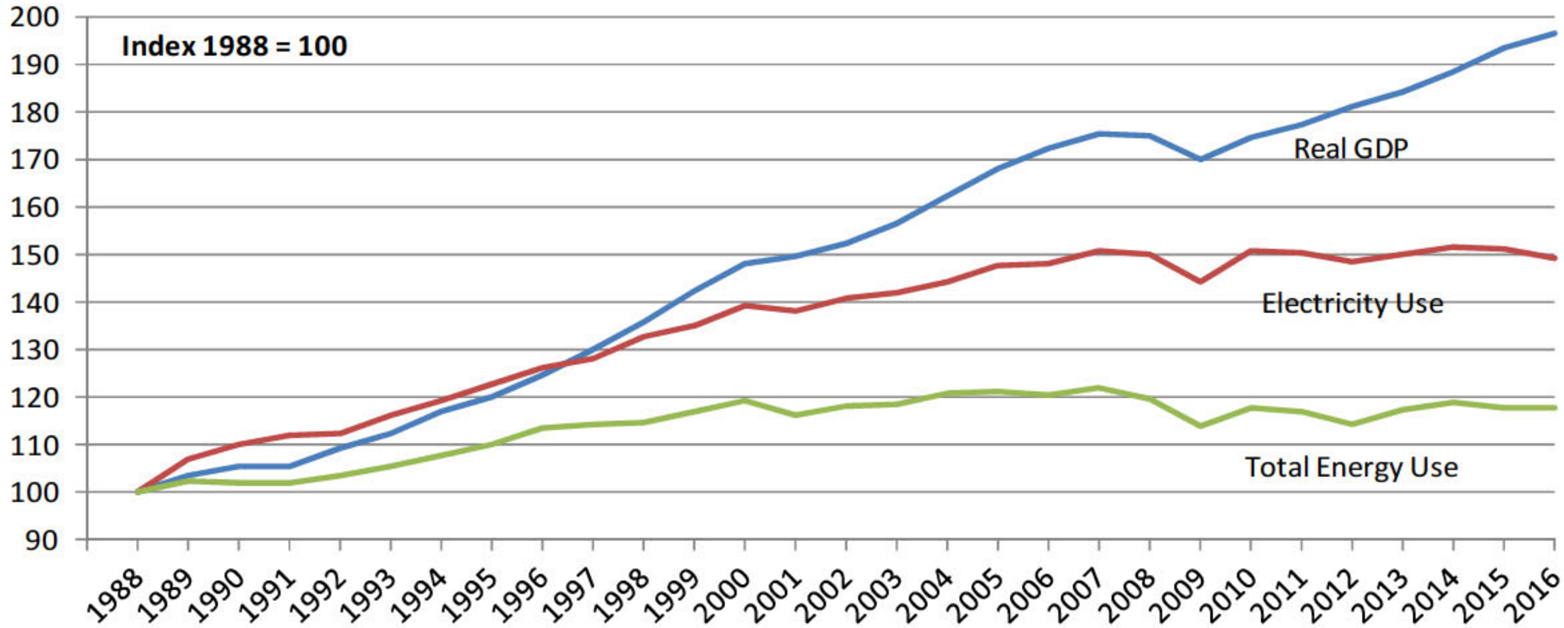
EXHIBIT AWEC/113

ELECTRICITY SALES ARE LINKED TO U.S. ECONOMIC GROWTH

April 20, 2018

Northwest Natural Gas Company

Electricity Sales Are Linked to U.S. Economic Growth



Note:
1988 represents the base year. Graph depicts increases or decreases from the base year.

Sources:
U.S. Energy Information Administration
Federal Reserve Bank of St. Louis

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EXHIBIT AWEC/114

MULTI-STAGE GROWTH DCF MODEL

April 20, 2018

Northwest Natural Gas Company

Multi-Stage Growth DCF Model

Line	Company	13-Week AVG Stock Price[1]	Annualized Dividend[2]	First Stage Growth[3]	Second Stage Growth Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth[4]	Multi-Stage Growth DCF
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Atmos Energy Corporation	$82.19	$1.94	7.05%	6.58%	6.10%	5.63%	5.15%	4.68%	4.20%	7.15%
2	Chesapeake Utilities Corporation	$72.35	$1.30	6.67%	6.26%	5.84%	5.43%	5.02%	4.61%	4.20%	6.37%
3	New Jersey Resources Corporation	$39.08	$1.09	6.33%	5.98%	5.62%	5.27%	4.91%	4.56%	4.20%	7.53%
4	Northwest Natural Gas Company	$56.89	$1.89	4.11%	4.13%	4.14%	4.16%	4.17%	4.19%	4.20%	7.64%
5	ONE Gas, Inc.	$68.64	$1.84	5.37%	5.17%	4.98%	4.78%	4.59%	4.39%	4.20%	7.20%
6	South Jersey Industries, Inc.	$28.87	$1.11	8.75%	7.99%	7.23%	6.48%	5.72%	4.96%	4.20%	9.46%
7	Southwest Gas Holdings, Inc.	$73.25	$1.98	4.00%	4.03%	4.07%	4.10%	4.13%	4.17%	4.20%	6.97%
8	Spire Inc.	$69.07	$2.25	4.98%	4.85%	4.72%	4.59%	4.46%	4.33%	4.20%	7.76%
9	WGL Holdings, Inc.	$84.41	$2.04	6.50%	6.12%	5.73%	5.35%	4.97%	4.58%	4.20%	7.11%
10	**Average**	**$63.86**	**$1.72**	**5.97%**	**5.68%**	**5.38%**	**5.09%**	**4.79%**	**4.50%**	**4.20%**	**7.47%**
11	**Median**										**7.20%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on March 19, 2018.
[2] *The Value Line Investment Survey*, March 2, 2018.
[3] AWEC/108.
[4] *Blue Chip Economic Indicators*, March 1, 2018 at 14.

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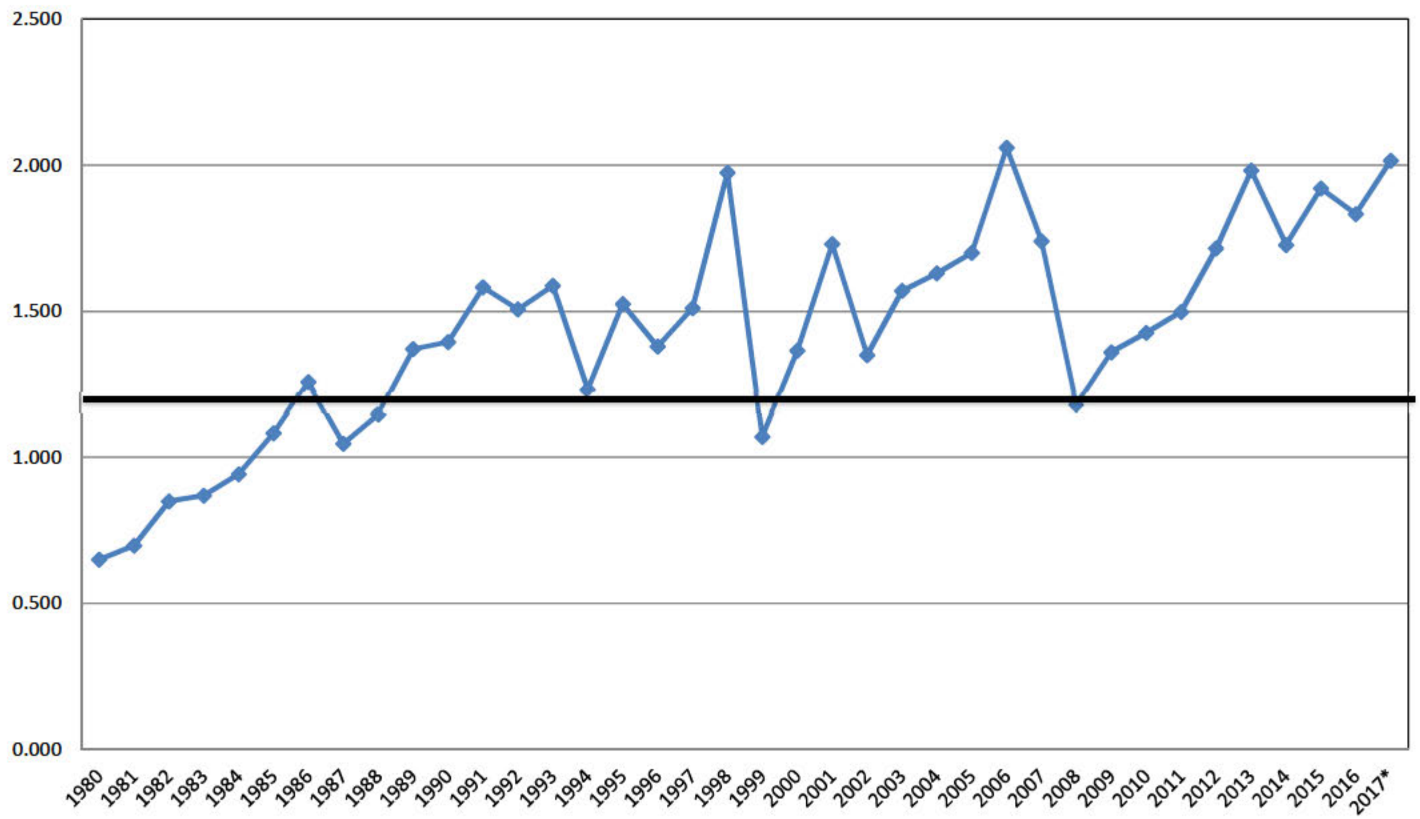
EXHIBIT AWEC/115

COMMON STOCK MARKET/BOOK RATIO

April 20, 2018

Northwest Natural Gas Company

Common Stock Market/Book Ratio



Source:
1980 - 2000: Mergent Public Utility Manual.
2001 - 2015: AUS Utility Reports, multiple dates.
2016 - 2017: Value Line Investment Survey, multiple dates.
* Value Line Investment Survey Reports, January 26, February 16, March 2, and March 16, 2018.

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EXHIBIT AWEC/116

EQUITY RISK PREMIUM – TREASURY BOND

April 20, 2018

Northwest Natural Gas Company

Equity Risk Premium - Treasury Bond

Line	Year	Authorized Gas Returns[1] (1)	30 yr. Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.46%	7.80%	5.66%		
2	1987	12.74%	8.58%	4.16%		
3	1988	12.85%	8.96%	3.89%		
4	1989	12.88%	8.45%	4.43%		
5	1990	12.67%	8.61%	4.06%	4.44%	
6	1991	12.46%	8.14%	4.32%	4.17%	
7	1992	12.01%	7.67%	4.34%	4.21%	
8	1993	11.35%	6.60%	4.75%	4.38%	
9	1994	11.35%	7.37%	3.98%	4.29%	
10	1995	11.43%	6.88%	4.55%	4.39%	4.42%
11	1996	11.19%	6.70%	4.49%	4.42%	4.30%
12	1997	11.29%	6.61%	4.68%	4.49%	4.35%
13	1998	11.51%	5.58%	5.93%	4.73%	4.55%
14	1999	10.66%	5.87%	4.79%	4.89%	4.59%
15	2000	11.39%	5.94%	5.45%	5.07%	4.73%
16	2001	10.95%	5.49%	5.46%	5.26%	4.84%
17	2002	11.03%	5.43%	5.60%	5.45%	4.97%
18	2003	10.99%	4.96%	6.03%	5.47%	5.10%
19	2004	10.59%	5.05%	5.54%	5.62%	5.25%
20	2005	10.46%	4.65%	5.81%	5.69%	5.38%
21	2006	10.40%	4.90%	5.50%	5.70%	5.48%
22	2007	10.22%	4.83%	5.39%	5.66%	5.55%
23	2008	10.39%	4.28%	6.11%	5.67%	5.57%
24	2009	10.22%	4.07%	6.15%	5.79%	5.70%
25	2010	10.15%	4.25%	5.90%	5.81%	5.75%
26	2011	9.92%	3.91%	6.01%	5.91%	5.80%
27	2012	9.94%	2.92%	7.02%	6.24%	5.95%
28	2013	9.68%	3.45%	6.23%	6.26%	5.97%
29	2014	9.78%	3.34%	6.44%	6.32%	6.06%
30	2015	9.60%	2.84%	6.76%	6.49%	6.15%
31	2016	9.54%	2.60%	6.94%	6.68%	6.29%
32	2017	9.72%	2.90%	6.83%	6.64%	6.44%
33	**Average**	**11.03%**	**5.61%**	**5.41%**	**5.36%**	**5.36%**
34	**Minimum**				**4.17%**	**4.30%**
35	**Maximum**				**6.68%**	**6.44%**

Sources:
[1] *Regulatory Research Associates, Inc* ., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 p. 5, and Jan. 2011 p. 3.
S&P Global Market Intelligence , RRA Regulatory Focus, Major Rate Case Decisions, January-December 2017, January 30, 2018, p. 5.
[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.

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EXHIBIT AWEC/117

EQUITY RISK PREMIUM – UTILITY BOND

April 20, 2018

Northwest Natural Gas Company

Equity Risk Premium - Utility Bond

Line	Year	Authorized Gas Returns[1] (1)	Average "A" Rated Utility Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.46%	9.58%	3.88%		
2	1987	12.74%	10.10%	2.64%		
3	1988	12.85%	10.49%	2.36%		
4	1989	12.88%	9.77%	3.11%		
5	1990	12.67%	9.86%	2.81%	2.96%	
6	1991	12.46%	9.36%	3.10%	2.80%	
7	1992	12.01%	8.69%	3.32%	2.94%	
8	1993	11.35%	7.59%	3.76%	3.22%	
9	1994	11.35%	8.31%	3.04%	3.21%	
10	1995	11.43%	7.89%	3.54%	3.35%	3.16%
11	1996	11.19%	7.75%	3.44%	3.42%	3.11%
12	1997	11.29%	7.60%	3.69%	3.49%	3.22%
13	1998	11.51%	7.04%	4.47%	3.64%	3.43%
14	1999	10.66%	7.62%	3.04%	3.64%	3.42%
15	2000	11.39%	8.24%	3.15%	3.56%	3.45%
16	2001	10.95%	7.76%	3.19%	3.51%	3.46%
17	2002	11.03%	7.37%	3.66%	3.50%	3.50%
18	2003	10.99%	6.58%	4.41%	3.49%	3.56%
19	2004	10.59%	6.16%	4.43%	3.77%	3.70%
20	2005	10.46%	5.65%	4.81%	4.10%	3.83%
21	2006	10.40%	6.07%	4.33%	4.33%	3.92%
22	2007	10.22%	6.07%	4.15%	4.43%	3.96%
23	2008	10.39%	6.53%	3.86%	4.32%	3.90%
24	2009	10.22%	6.04%	4.18%	4.27%	4.02%
25	2010	10.15%	5.47%	4.68%	4.24%	4.17%
26	2011	9.92%	5.04%	4.88%	4.35%	4.34%
27	2012	9.94%	4.13%	5.81%	4.68%	4.55%
28	2013	9.68%	4.48%	5.20%	4.95%	4.63%
29	2014	9.78%	4.28%	5.50%	5.22%	4.74%
30	2015	9.60%	4.12%	5.48%	5.38%	4.81%
31	2016	9.54%	3.93%	5.61%	5.52%	4.94%
32	2017	9.72%	4.00%	5.72%	5.50%	5.09%
33	**Average**	**11.03%**	**6.99%**	**4.04%**	**3.99%**	**3.95%**
34	**Minimum**				**2.80%**	**3.11%**
35	**Maximum**				**5.52%**	**5.09%**

Sources:

[1] *Regulatory Research Associates, Inc*., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 p. 5, and Jan. 2011 p. 3.
S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions, January-December 2017, January 30, 2018, p. 5.

[2] Mergent Public Utility Manual, Mergent Weekly News Reports, 2003.
The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record.
The utility yields from 2010-2017 were obtained from http://credittrends.moodys.com/.

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EXHIBIT AWEC/118

BOND YIELD SPREADS

April 20, 2018

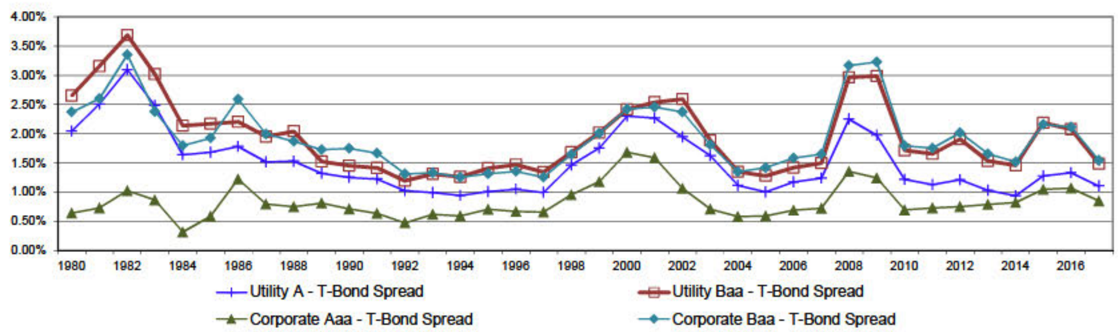
Northwest Natural Gas Company

Bond Yield Spreads

			Public Utility Bond				Corporate Bond				Utility to Corporate	
Line	Year	T-Bond Yield[1] (1)	A[2] (2)	Baa[2] (3)	A-T-Bond Spread (4)	Baa-T-Bond Spread (5)	Aaa[3] (6)	Baa[3] (7)	Aaa-T-Bond Spread (8)	Baa-T-Bond Spread (9)	Baa Spread (10)	A-Aaa Spread (11)
1	1980	11.30%	13.34%	13.95%	2.04%	2.65%	11.94%	13.67%	0.64%	2.37%	0.28%	1.40%
2	1981	13.44%	15.95%	16.60%	2.51%	3.16%	14.17%	16.04%	0.73%	2.60%	0.56%	1.78%
3	1982	12.76%	15.86%	16.45%	3.10%	3.69%	13.79%	16.11%	1.03%	3.35%	0.34%	2.07%
4	1983	11.18%	13.66%	14.20%	2.48%	3.02%	12.04%	13.55%	0.86%	2.38%	0.65%	1.62%
5	1984	12.39%	14.03%	14.53%	1.64%	2.14%	12.71%	14.19%	0.32%	1.80%	0.34%	1.32%
6	1985	10.79%	12.47%	12.96%	1.68%	2.17%	11.37%	12.72%	0.58%	1.93%	0.24%	1.10%
7	1986	7.80%	9.58%	10.00%	1.78%	2.20%	9.02%	10.39%	1.22%	2.59%	-0.39%	0.56%
8	1987	8.58%	10.10%	10.53%	1.52%	1.95%	9.38%	10.58%	0.80%	2.00%	-0.05%	0.72%
9	1988	8.96%	10.49%	11.00%	1.53%	2.04%	9.71%	10.83%	0.75%	1.87%	0.17%	0.78%
10	1989	8.45%	9.77%	9.97%	1.32%	1.52%	9.26%	10.18%	0.81%	1.73%	-0.21%	0.51%
11	1990	8.61%	9.86%	10.06%	1.25%	1.45%	9.32%	10.36%	0.71%	1.75%	-0.30%	0.54%
12	1991	8.14%	9.36%	9.55%	1.22%	1.41%	8.77%	9.80%	0.63%	1.67%	-0.25%	0.59%
13	1992	7.67%	8.69%	8.86%	1.02%	1.19%	8.14%	8.98%	0.47%	1.31%	-0.12%	0.55%
14	1993	6.60%	7.59%	7.91%	0.99%	1.31%	7.22%	7.93%	0.62%	1.33%	-0.02%	0.37%
15	1994	7.37%	8.31%	8.63%	0.94%	1.26%	7.96%	8.62%	0.59%	1.25%	0.01%	0.35%
16	1995	6.88%	7.89%	8.29%	1.01%	1.41%	7.59%	8.20%	0.71%	1.32%	0.09%	0.30%
17	1996	6.70%	7.75%	8.17%	1.05%	1.47%	7.37%	8.05%	0.67%	1.35%	0.12%	0.38%
18	1997	6.61%	7.60%	7.95%	0.99%	1.34%	7.26%	7.86%	0.66%	1.26%	0.09%	0.34%
19	1998	5.58%	7.04%	7.26%	1.46%	1.68%	6.53%	7.22%	0.95%	1.64%	0.04%	0.51%
20	1999	5.87%	7.62%	7.88%	1.75%	2.01%	7.04%	7.87%	1.18%	2.01%	0.01%	0.58%
21	2000	5.94%	8.24%	8.36%	2.30%	2.42%	7.62%	8.36%	1.68%	2.42%	-0.01%	0.62%
22	2001	5.49%	7.76%	8.03%	2.27%	2.54%	7.08%	7.95%	1.59%	2.45%	0.08%	0.68%
23	2002	5.43%	7.37%	8.02%	1.94%	2.59%	6.49%	7.80%	1.06%	2.37%	0.22%	0.88%
24	2003	4.96%	6.58%	6.84%	1.62%	1.89%	5.67%	6.77%	0.71%	1.81%	0.08%	0.91%
25	2004	5.05%	6.16%	6.40%	1.11%	1.35%	5.63%	6.39%	0.58%	1.35%	0.00%	0.53%
26	2005	4.65%	5.65%	5.93%	1.00%	1.28%	5.24%	6.06%	0.59%	1.42%	-0.14%	0.41%
27	2006	4.90%	6.07%	6.32%	1.17%	1.42%	5.59%	6.48%	0.69%	1.58%	-0.16%	0.48%
28	2007	4.83%	6.07%	6.33%	1.24%	1.50%	5.56%	6.48%	0.72%	1.65%	-0.15%	0.52%
29	2008	4.28%	6.53%	7.25%	2.25%	2.97%	5.63%	7.45%	1.35%	3.17%	-0.20%	0.90%
30	2009	4.07%	6.04%	7.06%	1.97%	2.99%	5.31%	7.30%	1.24%	3.23%	-0.24%	0.73%
31	2010	4.25%	5.47%	5.96%	1.22%	1.71%	4.95%	6.04%	0.70%	1.79%	-0.08%	0.52%
32	2011	3.91%	5.04%	5.57%	1.13%	1.66%	4.64%	5.67%	0.73%	1.76%	-0.10%	0.40%
33	2012	2.92%	4.13%	4.83%	1.21%	1.90%	3.67%	4.94%	0.75%	2.02%	-0.11%	0.46%
34	2013	3.45%	4.48%	4.98%	1.03%	1.53%	4.24%	5.10%	0.79%	1.65%	-0.12%	0.24%
35	2014	3.34%	4.28%	4.80%	0.94%	1.46%	4.16%	4.86%	0.82%	1.52%	-0.06%	0.12%
36	2015	2.84%	4.12%	5.03%	1.27%	2.19%	3.89%	5.00%	1.05%	2.16%	0.03%	0.23%
37	2016	2.60%	3.93%	4.67%	1.33%	2.08%	3.66%	4.71%	1.07%	2.12%	-0.04%	0.27%
38	2017	2.90%	4.00%	4.38%	1.10%	1.48%	3.74%	4.44%	0.85%	1.55%	-0.06%	0.26%
39	**Average**	**6.62%**	**8.13%**	**8.57%**	**1.51%**	**1.95%**	**7.46%**	**8.55%**	**0.84%**	**1.93%**	**0.01%**	**0.67%**

Yield Spreads

Treasury Vs. Corporate & Treasury Vs. Utility



Sources:

[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.

[2] The utility yields for the period 1980-2000 were obtained from Mergent Public Utility Manual, Mergent Weekly News Reports, 2003.
The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record.
The utility yields for the period 2010-2017 were obtained from http://credittrends.moodys.com/.

[3] The corporate yields for the period 1980-2009 were obtained from the St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The corporate yields from 2010-2017 were obtained from http://credittrends.moodys.com/.

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EXHIBIT AWEC/119

TREASURY AND UTILITY BOND YIELDS

April 20, 2018

Northwest Natural Gas Company

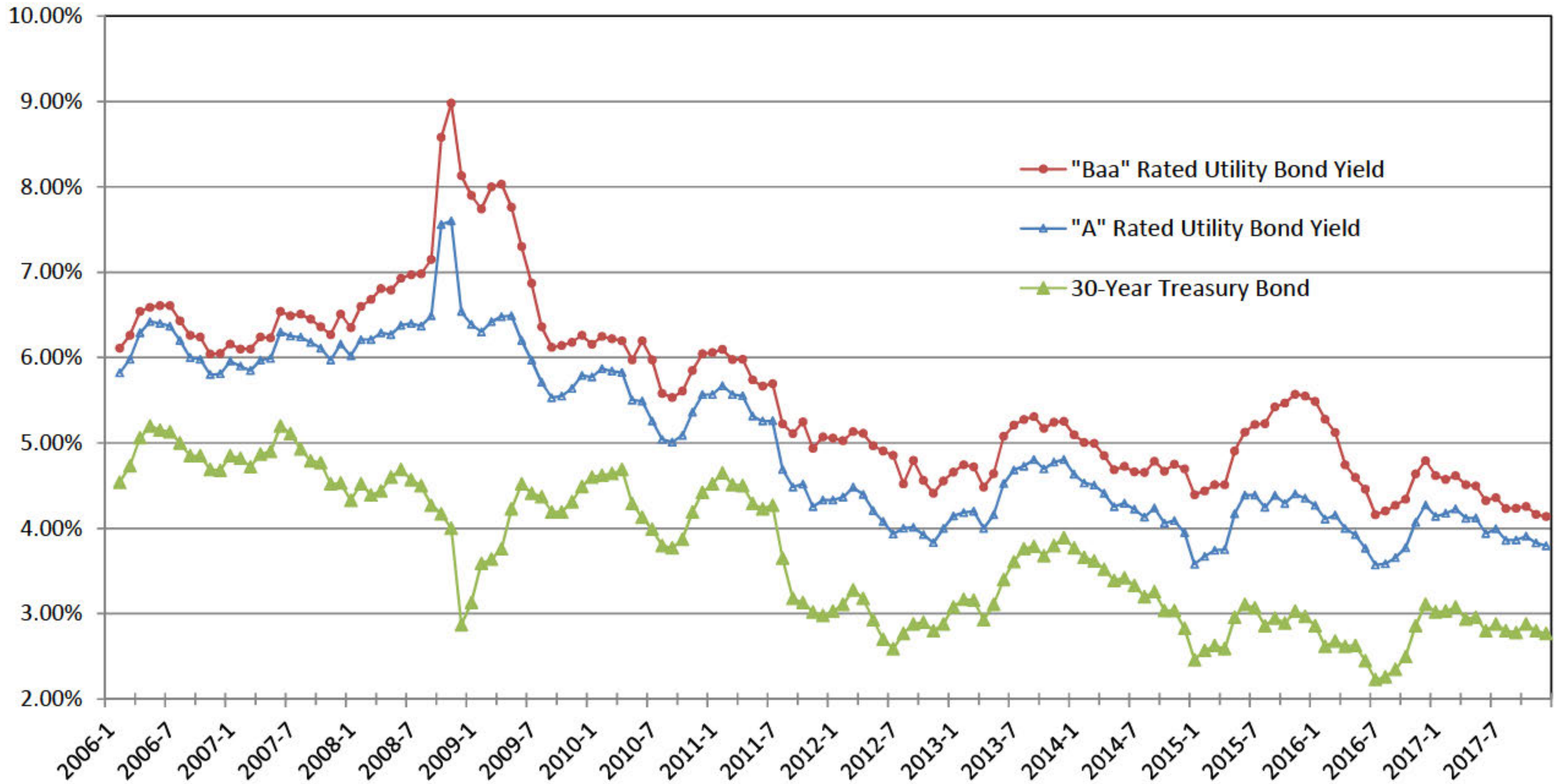
Treasury and Utility Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (3)	"Baa" Rated Utility Bond Yield[2] (4)
1	03/16/18	3.08%	4.12%	4.52%
2	03/09/18	3.16%	4.18%	4.55%
3	03/02/18	3.14%	4.12%	4.46%
4	02/23/18	3.16%	4.12%	4.46%
5	02/16/18	3.13%	4.10%	4.43%
6	02/09/18	3.14%	4.08%	4.41%
7	02/02/18	3.08%	4.04%	4.35%
8	01/26/18	2.91%	3.88%	4.19%
9	01/19/18	2.91%	3.89%	4.21%
10	01/12/18	2.85%	3.84%	4.16%
11	01/05/18	2.81%	3.82%	4.15%
12	12/28/17	2.75%	3.77%	4.11%
13	12/22/17	2.83%	3.85%	4.19%
14	**Average**	**3.00%**	**3.99%**	**4.32%**
15	**Spread To Treasury**		**0.99%**	**1.32%**

Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[2] http://credittrends.moodys.com/.

Northwest Natural Gas Company

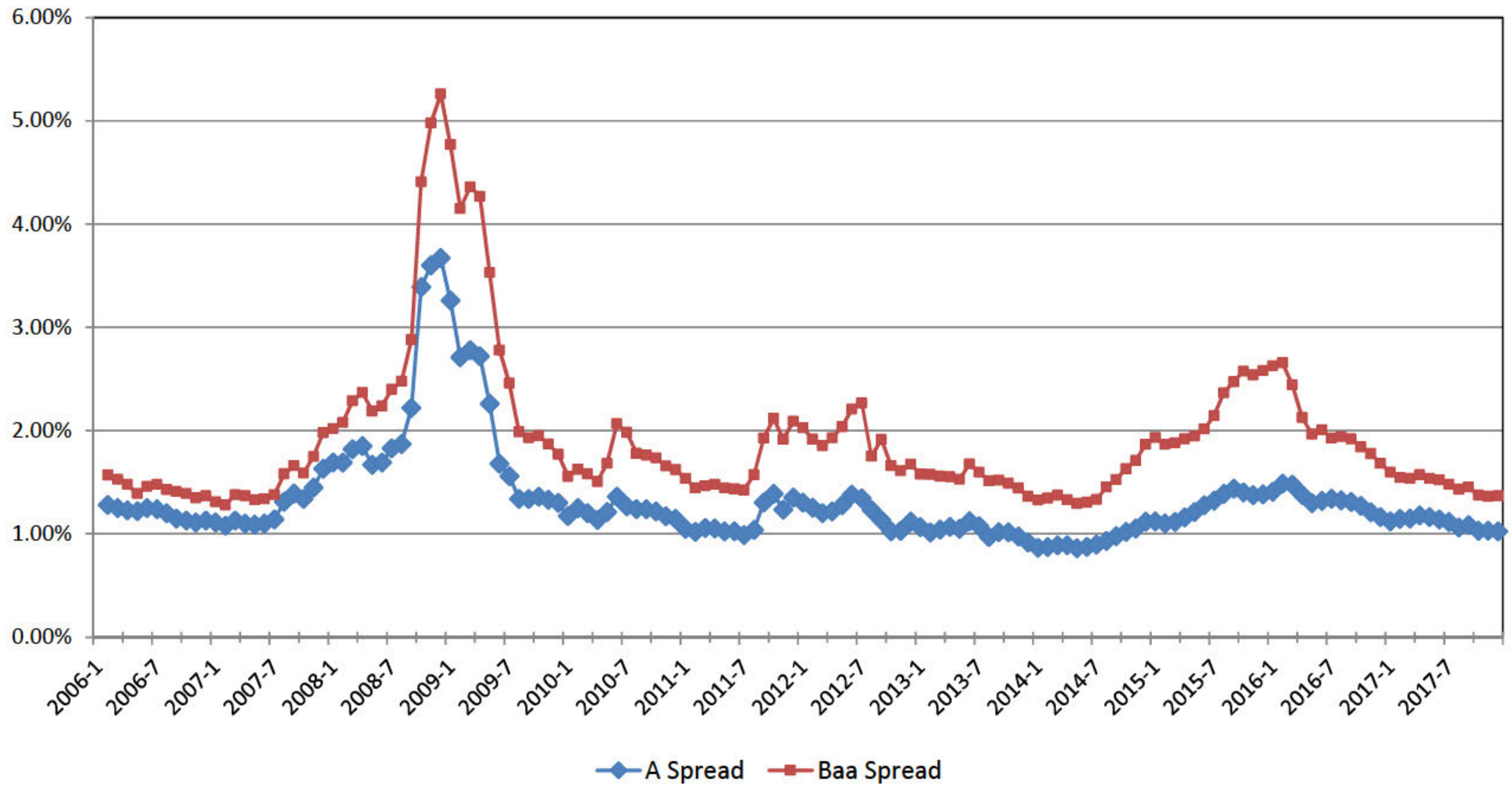
Trends in Bond Yields



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

Northwest Natural Gas Company

Yield Spread Between Utility Bonds and 30-Year Treasury Bonds



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

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EXHIBIT AWEC/120

VALUE LINE BETA

April 20, 2018

Northwest Natural Gas Company

Value Line Beta

Line	Company	Beta
1	Atmos Energy Corporation	0.70
2	Chesapeake Utilities Corporation	0.70
3	New Jersey Resources Corporation	0.75
4	Northwest Natural Gas Company	0.65
5	ONE Gas, Inc.	0.70
6	South Jersey Industries, Inc.	0.80
7	Southwest Gas Holdings, Inc.	0.75
8	Spire Inc.	0.65
9	WGL Holdings, Inc.	0.80
10	**Average**	**0.72**

Source:
The Value Line Investment Survey,
March 2, 2018.

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EXHIBIT AWEC/121

CAPM RETURN

April 20, 2018

Northwest Natural Gas Company

CAPM Return

Line	Description	High Market Risk Premium (1)	Low Market Risk Premium (2)
1	Risk-Free Rate[1]	3.70%	3.70%
2	Risk Premium[2]	7.70%	6.00%
3	Beta[3]	0.72	0.72
4	**CAPM**	**9.26%**	**8.03%**

Sources:
[1] *Blue Chip Financial Forecasts*, March 1, 2018, at 2.
[2] *Duff & Phelps, 2017 SBBI Yearbook* at 6-17 and 6-18, and
Duff & Phelps, 2017 Valuation Handbook at 3-36 and 3-48.
[3] AWEC/120.

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EXHIBIT AWEC/122

ACCURACY OF INTEREST RATE FORECASTS

April 20, 2018

Northwest Natural Gas Company

Accuracy of Interest Rate Forecasts
(Long-Term Treasury Bond Yields - Projected Vs. Actual)

Line	Date	Publication Data: Prior Quarter Actual Yield (1)	Publication Data: Projected Yield (2)	Publication Data: Projected Quarter (3)	Actual Yield in Projected Quarter (4)	Projected Yield Higher (Lower) Than Actual Yield* (5)
1	Dec-00	5.8%	5.8%	1Q, 02	5.6%	0.2%
2	Mar-01	5.7%	5.6%	2Q, 02	5.8%	-0.2%
3	Jun-01	5.4%	5.8%	3Q, 02	5.2%	0.6%
4	Sep-01	5.7%	5.9%	4Q, 02	5.1%	0.8%
5	Dec-01	5.5%	5.7%	1Q, 03	5.0%	0.7%
6	Mar-02	5.3%	5.9%	2Q, 03	4.7%	1.2%
7	Jun-02	5.6%	6.2%	3Q, 03	5.2%	1.0%
8	Sep-02	5.8%	5.9%	4Q, 03	5.2%	0.7%
9	Dec-02	5.2%	5.7%	1Q, 04	4.9%	0.8%
10	Mar-03	5.1%	5.7%	2Q, 04	5.4%	0.3%
11	Jun-03	5.0%	5.4%	3Q, 04	5.1%	0.3%
12	Sep-03	4.7%	5.8%	4Q, 04	4.9%	0.9%
13	Dec-03	5.2%	5.9%	1Q, 05	4.8%	1.1%
14	Mar-04	5.2%	5.9%	2Q, 05	4.6%	1.4%
15	Jun-04	4.9%	6.2%	3Q, 05	4.5%	1.7%
16	Sep-04	5.4%	6.0%	4Q, 05	4.8%	1.2%
17	Dec-04	5.1%	5.8%	1Q, 06	4.6%	1.2%
18	Mar-05	4.9%	5.6%	2Q, 06	5.1%	0.5%
19	Jun-05	4.8%	5.5%	3Q, 06	5.0%	0.5%
20	Sep-05	4.6%	5.2%	4Q, 06	4.7%	0.5%
21	Dec-05	4.5%	5.3%	1Q, 07	4.8%	0.5%
22	Mar-06	4.8%	5.1%	2Q, 07	5.0%	0.1%
23	Jun-06	4.6%	5.3%	3Q, 07	4.9%	0.4%
24	Sep-06	5.1%	5.2%	4Q, 07	4.6%	0.6%
25	Dec-06	5.0%	5.0%	1Q, 08	4.4%	0.6%
26	Mar-07	4.7%	5.1%	2Q, 08	4.6%	0.5%
27	Jun-07	4.8%	5.1%	3Q, 08	4.5%	0.7%
28	Sep-07	5.0%	5.2%	4Q, 08	3.7%	1.5%
29	Dec-07	4.9%	4.8%	1Q, 09	3.5%	1.4%
30	Mar-08	4.6%	4.8%	2Q, 09	4.0%	0.8%
31	Jun-08	4.4%	4.9%	3Q, 09	4.3%	0.6%
32	Sep-08	4.6%	5.1%	4Q, 09	4.3%	0.8%
33	Dec-08	4.5%	4.6%	1Q, 10	4.6%	0.0%
34	Mar-09	3.7%	4.1%	2Q, 10	4.4%	-0.3%
35	Jun-09	3.5%	4.6%	3Q, 10	3.9%	0.8%
36	Sep-09	4.0%	5.0%	4Q, 10	4.2%	0.8%
37	Dec-09	4.3%	5.0%	1Q, 11	4.6%	0.4%
38	Mar-10	4.3%	5.2%	2Q, 11	4.3%	0.9%
39	Jun-10	4.6%	5.2%	3Q, 11	3.7%	1.5%
40	Sep-10	4.4%	4.7%	4Q, 11	3.0%	1.7%
41	Dec-10	3.9%	4.6%	1Q, 12	3.1%	1.5%
42	Mar-11	4.2%	5.1%	2Q, 12	2.9%	2.2%
43	Jun-11	4.6%	5.2%	3Q, 12	2.8%	2.5%
44	Sep-11	4.3%	4.2%	4Q, 12	2.9%	1.3%
45	Dec-11	3.7%	3.8%	1Q, 13	3.1%	0.7%
46	Mar-12	3.0%	3.8%	2Q, 13	3.2%	0.7%
47	Jun-12	3.1%	3.7%	3Q, 13	3.7%	0.0%
48	Sep-12	2.9%	3.4%	4Q, 13	3.8%	-0.4%
49	Dec-12	2.8%	3.4%	1Q, 14	3.7%	-0.3%
50	Mar-13	2.9%	3.6%	2Q, 14	3.4%	0.2%
51	Jun-13	3.1%	3.7%	3Q, 14	3.3%	0.4%
52	Sep-13	3.2%	4.2%	4Q, 14	3.0%	1.2%
53	Dec-13	3.7%	4.2%	1Q, 15	2.6%	1.7%
54	Mar-14	3.8%	4.4%	2Q 15	2.9%	1.5%
55	Jun-14	3.7%	4.3%	3Q 15	2.8%	1.5%
56	Sep-14	3.4%	4.3%	4Q 15	3.0%	1.3%
57	Dec-14	3.3%	4.0%	1Q 16	2.7%	1.3%
58	Mar-15	3.0%	3.7%	2Q 16	2.6%	1.1%
59	Jun-15	2.6%	3.7%	3Q 16	2.3%	1.4%
60	Sep-15	2.9%	3.8%	4Q 16	2.8%	1.0%
61	Dec-15	2.8%	3.7%	1Q 17	3.0%	0.7%
62	Mar-16	3.0%	3.5%	2Q 17	2.9%	0.6%
63	Jun-16	2.7%	3.4%	3Q 17	2.8%	0.6%
64	Sep-16	2.6%	3.1%	4Q 17	2.8%	0.3%
65	Dec-16	2.3%	3.4%	1Q 18		
66	Jan-17	2.8%	3.7%	2Q 18		
67	Feb-17	2.8%	3.7%	2Q 18		
68	Mar-17	2.8%	3.7%	2Q 18		
69	Apr-17	3.1%	3.8%	3Q 18		
70	May-17	3.0%	3.7%	3Q 18		
71	Jun-17	3.0%	3.7%	3Q 18		
72	Jul-17	2.9%	3.7%	4Q 18		
73	Aug-17	2.9%	3.7%	4Q 18		
74	Sep-17	2.9%	3.6%	4Q 18		
75	Oct-17	2.8%	3.6%	1Q 19		
76	Nov-17	2.8%	3.6%	1Q 19		
77	Dec-17	2.8%	3.6%	1Q 19		
78	Jan-18	2.8%	3.6%	2Q 19		
79	Feb-18	2.8%	3.6%	2Q 19		
80	Mar-18	2.8%	3.7%	2Q 19		

Source:
Blue Chip Financial Forecasts, Various Dates.
* Col. 2 - Col. 4.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL,	)
	)
Request for a General Rate Revision.	)

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

April 20, 2018

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EXHIBIT LIST

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and 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, with a primary focus in the Pacific Northwest. I am appearing in this matter 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 gas customers of Northwest Natural Gas Company ("NW Natural"). AWEC was formed April 1, 2018, as a result of the merger of Northwest Industrial Gas Users into the Industrial Customers of Northwest Utilities.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. A summary of my education and work experience can be found at AWEC/201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my initial review of NW Natural's revenue requirement. In its Direct Testimony, NW Natural requested a revenue increase of approximately $52,446,470. On March 20, 2018, NW Natural filed an update to its revenue requirement where it reduced that requested increase to $37,815,882. The March 20, 2018 update incorporated some, but not all, of the revenue requirement impacts of the Tax Cuts and Jobs Act.

Q. WHAT WAS THE SCOPE OF YOUR REVIEW?

A. My review was focused on tax expense, including the impact of the Tax Cuts and Jobs Act, capital projections and other miscellaneous revenue requirement issues. My recommendation incorporates the 9.15% return on equity recommendation of Mr. Gorman, who is also submitting testimony on behalf of AWEC in this matter.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS.

A. Based on the adjustments detailed in Table 1, below, I calculate a revenue sufficiency of $12,489,774, relative to the rates approved in Docket No. UG 221 (the "2012 GRC"). Calculation underlying the revenue requirement adjustments in Table 1, including the rate base and operating income impacts, can be found in Exhibit AWEC/202, and brief issue summaries follow the table.

TABLE 1
Contested Revenue Requirement Adjustments
Deficiency / (Sufficiency) ($000)

1	**NW Natural Initial Filing**			**52,446**
	Adjustments:			
2	A1	Return on Equity (9.15%)	(8,651)	
3	A2	ADIT - Accrued Vacation	(250)	
4	A3	R&D Tax Credit	(75)	
5	TCJA-1	Restate Tax Expense	(13,265)	
6	TCJA-2	Excess Deferred Taxes	(13,498)	
7	TCJA-3	Interim Period Deferral	(7,917)	
8	TCJA-4	TCJA Conversion Factor	(1,558)	
9	A4	Rate Base Cut-Off	(3,898)	
10	A5	Non-Discrete Capital	(12,698)	
11	A6	Mid-Willamette Feeder Project	(2,047)	
12	A7	Corvallis Loop Project	(859)	
13	A8	SE Eugene Project	(744)	
14	A9	Stock Issuance Costs	(1,233)	
15	A10	Interest Synch	1,756	
16	**Total Adjustments**			**(64,936)**
17	**Adjusted**			**(12,490)**

1. **ADIT - Accrued Vacation.** Since ratepayers do not receive the benefit from accrued vacation through a reduction in rate base, the deferred tax impacts of accrued vacation should be excluded from NW Natural's rate base.

2. **R&D Tax Credits.** I propose a minor correction to R&D tax credits in the calculation of tax expense.

3. **TCJA-1 – Restate Tax Expense**. This adjustment restates the income tax expense included in results at the new 21% federal corporate tax rate.

4. **TCJA-2 – Excess Deferred Federal Income Taxes.** This adjustment incorporates the impact of the new 21% corporate tax rate on NW Natural's accumulated deferred income tax balances.

5. **TCJA-3 – Amortize Interim Period Deferral.** This adjustment incorporates amortization of excess tax expenses reflected in revenue requirement deferred over the period January 1, 2018 through October 31, 2018.

6. **TCJA-4 – Conversion Factor.** This adjustment isolates the impact of the 21% in calculating the revenue surplus or deficiency associated with test period result.

7. **Post-Rate Effective Period Capital.** This adjustment removes forecast capital expenditures beyond November 1, 2018, since those amounts will not be in service by the rate effective date.

8. **Non-Discrete Capital Additions.** Despite multiple requests, NW Natural has not provided the data necessary to support its forecast of non-discrete capital additions. This adjustment removes those unsupported amounts.

9. **Mid-Willamette Feeder Project.** NW Natural has not presented anything new to justify including the Mid-Willamette Feeder project, which was previously disallowed by the Commission, in rates.

10. **Corvallis Loop Project.** This adjustment removes the Corvallis Loop Project budget variance since those amounts were a result of mismanagement.

11. **SE Eugene Project.** Construction of this project has been delayed and has not yet been initiated. Accordingly, it is premature to include this project in rate base.

12. **Stock Issuance Costs.** Stock issuance costs are not an expense, but a reduction to the proceeds received through the issuance of stock. This adjustment removes historical stock issuance costs from revenue requirement.

I will discuss these issues in respective order in the following sections and subsections of my testimony.

II. GENERAL TAX ISSUES

Q. BEFORE DISCUSSING THE IMPACT OF THE TAX CUTS AND JOBS ACT ADJUSTMENTS, DO YOU HAVE ANY UNRELATED TAX ISSUES TO DISCUSS?

A. Yes. I have identified a few tax issues that are unrelated to the Tax Cuts and Jobs Act. Since the order of operation impacts my revenue requirement study, these adjustments were applied first before determining the impact of the reduced corporate tax rate, and other change resulting from the Tax Cuts and Jobs Act.

a. <u>ADIT – Accrued Vacation</u>

Q. WHAT AMOUNT OF ADIT HAS NW NATURAL INCLUDED IN REVENUE REQUIREMENT RELATED TO ACCRUED VACATION?

A. In NWN/210, NW Natural included other accumulated deferred federal income taxes ("ADIT") of (-)$15,598,283, with (-)$14,144,643 allocated to Oregon. In response to NWIGU Data Request 8, NW Natural was asked to provide a break down of the other ADIT amounts included in rate base. Based on that response, NW Natural included a debit balance of approximately $2,241,127 ($2,032,271 Oregon-allocated) for ADIT related to accrued vacation in the forecast period.

Q. IS THE ADIT ASSOCIATED WITH ACCRUED VACATION APPROPRIATELY INCLUDED IN RATE BASE?

A. No. ADIT related to accrued vacation arises due to a timing difference of when those costs are incurred for GAAP purposes and when they are deductible for tax purposes. For GAAP purposes, an amount is deduced against operating revenues when an employee earns the vacation days. For tax purposes, those amounts are only deducted when paid, *i.e.* when the employee actually uses the accrued vacation days. Since ratepayers do not receive a financing benefit as a result of this timing difference through a reduction in rate base, its not appropriate for ratepayers to incur the deferred tax consequences resulting from such timing difference.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT RELATED TO ACCRUED VACATION?

A. Removing the $2,032,271 ADIT amount from rate base results in a reduction of $250,328 reduction to revenue requirement.

b. <u>Research and Development Tax Credits</u>

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO RESEARCH AND DEVELOPMENT TAX CREDITS?

A. NW Natural included a research and development tax credit amount in its tax expense of $76,018. I have made a minor change to that amount be more consistent with the level of research funding expected in the test period.

Q. WHAT CHANGES DID YOU MAKE?

A. I updated the calculation to be based on the expected level of energy research consortium expenditures in the test period. NW Natural's credit calculation was based on a calculation performed for 2015, which assumed consortium expenditures of $575,000. In Attachment 5 to NWIGU Data Request 44, NW Natural reported $800,000 for energy consortium payments in 2016. That amount, however, was slightly different than the 2016 tax return value of $750,000. I also recalculated an aspect of the alternative simplified credit calculation, called a § 280C adjustment, to be based on the lower 21% tax rate.

Q. WHAT LEVEL OF RESEARCH EXPENDITURES DO YOU PROPOSE?

A. I recommend using the $750,000 amount included on the 2016 tax return. Doing so results in an increase to the credit amount of $120,041. That results in a reduction to tax expense of $44,023, which equates to $75,398 of revenue requirement on a pre-tax basis.

III. TAX CUTS AND JOBS ACT ADJUSTMENTS

Q. PLEASE PROVIDE SOME BACKGROUND ON THE TAX CUTS AND JOBS ACT.

A. The Tax Cuts and Jobs Act ("TCJA"), HR 1 of the 115th Congress, was signed into law on December 22, 2017. Among other things, the TCJA resulted in a reduction to the Federal corporate income tax rate from 35% to 21%.

Q. DID NW NATURAL'S INITIAL FILING INCLUDE THE IMPACT OF THE TCJA?

A. No. NW Natural filed its application on December 29, 2017, after the TCJA became a public law, but the benefits of the TCJA were not included in its revenue requirement. It certainly takes some time to understand the effects of legislation such as the TCJA. Notwithstanding, the impacts of this legislation are so significant, it would have been appropriate for NW Natural to take the time to understand the tax change prior to filing its application to increase its rates by such significant amounts.

Q. HAS NW NATURAL SUBSEQUENTLY UPDATED ITS REVENUE REQUIREMENT TO INCLUDE THE IMPACTS OF THE TCJA?

A. Yes. On March 20, 2018, NW Natural filed a revenue requirement update where it attempted to incorporate the impacts of the TCJA, as well as other corrections and updates. It's update, however, lacked sufficient information to understand how NW Natural proposed to consider the tax change, or the changes that were made relative to the initial filing. Its workpapers were equally insufficient, as NW Natural did not even supply a working copy of the revenue requirement model when it filed this update. That filing was inadequate, as it omitted large portions of the TCJA impacts on revenue requirement. As I result of those problems, I have not considered the NW Natural's update and, and have performed my own calculations of the relevant impacts of the TCJA on the filed revenue requirement.

Q. HOW DOES THE TCJA AFFECT THE CALCULATION OF REVENUE REQUIREMENT?

A. The TCJA impacts revenue requirement in at least four ways. First, federal income tax expense included in the results of operations table must be stated—or in this case *re*stated—at the lower, 21% rate. Second, balances associated with ADIT must be revalued at the new rate, including consideration of previously over-deferred amounts, often referred to as Excess Deferred Federal Income Taxes ("EDFIT"). Third, the tax expenses over-collected in rates over the period January 1, 2018 through October 31, 2018 (the "Interim Period") must be deferred and amortized to results. Fourth, the conversion factor used in the calculation of the revenue deficiency or surplus must be updated to reflect the TCJA.

A fifth area of concern is the forecasting of incremental deferred taxes in the pro forma period, including the impacts associated with bonus depreciation such as the domestic production activities deduction.

a. <u>TCJA-1: Restate Federal Income Tax Expense</u>

Q. HOW DOES THE TCJA IMPACT TAX EXPENSES INCLUDED IN NW NATURAL'S RESULTS OF OPERATIONS?

A. The first, and most straight-forward adjustment with respect to the TCJA is to recalculate the income tax expenses reflected in the adjusted results of operations table based upon the lower 21% federal income tax rate, in contrast to the 35% tax rate assumed in NW Natural's initial filing. This adjustment applies to both current and deferred income tax expenses. This adjustment can be calculated by multiplying the sum of current taxable income and deferred tax items by the lower 21% corporate tax rate.

Q. HAVE YOU PERFORMED THIS CALCULATION?

A. I have performed this calculation in Exhibit AWEC/203, based upon the tax expense in Exhibit NWN/207. The result is a reduction to post-tax operating income of $7,745,116, which corresponds to a revenue requirement reduction of $13,264,953.

b. <u>TCJA-2: Excess Deferred Federal Income Taxes</u>

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO EXCESS DEFERRED FEDERAL INCOME TAXES?

A. I recommend that Excess Deferred Federal Income Taxes be passed back to ratepayers through a reduction to base rates in this matter. The treatment of the EDFIT amounts is central to the overall implementation of the TCJA, yet NW Natural did not address this issue in its Supplemental Testimony. Further, based on its responses to data requests, NW Natural has implied that it should be entitled to retain those amounts. I disagree. Not only would that violate normalization requirements, it is an unreasonable request because these funds belong to customers. I propose to return those amounts to ratepayers through base rates.

Q. WHAT ARE EXCESS DEFERRED FEDERAL INCOME TAXES?

A. The TCJA contains new normalization provisions surrounding EDFIT, which simplifies the treatment of the balance sheet impacts of the tax law change for public utilities. 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 retuned to ratepayers.

Under Generally Accepted Accounting Principles, 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."[1] 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 will result in material balance sheet impacts. For a non-utility business enterprise, deferred tax liabilities—funds that the entity is effectively holding in reserve to pay for future taxes—must be revalued at the new tax rate. 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. Under the normalization requirements of IRC § 168(i)(9), the balance sheet gains associated with the change in tax rate must remain on the public utility's balance sheet, and instead of recognizing the gains in one lump sum, the gains are amortized over an extended period of time. A few methods are available to amortize the gains, but the amortization period is generally intended to correspond to the period over which the underlying book-tax differences are expected to reverse.

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

A. The IRS normalization requirements apply only to deferred tax balances associated with the use of accelerated depreciation—both Modified Accelerated Cost Recovery System

[1] 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 ("ACS") 740-25-47.

("MACRS") and bonus depreciation—in IRC § 168k. Accordingly, normalization accounting methods outlined in the TCJA only apply to those 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 the Commission has greater leeway in determining how the gains on those balances resulting from the TCJA get returned to ratepayers.

Q. WHAT AMOUNT OF PROTECTED AND UNPROTECTED EDFIT DID NW NATURAL RECORD AS OF DECEMBER 31, 2017?

A. In response to NWIGU Data Request 36, Attachment 1, NW Natural reported ADIT credit balance associated with fixed assets of $350,939,864, before revaluation under the 21% tax rate. After being remeasured, the liability balance declines to $210,563,919. The $140,375,946 reduction, rather than flowing through to earnings, represents protected EDFIT. On an Oregon-allocated basis, that EDFIT amount is $126,270,885. Note that these amounts exclude ADIT associated with the Willamette Valley Feeder.

For several categories, it was unclear whether the amounts were more appropriately considered protected or unprotected. For example, EDFIT balances of $18,154,514 under the heading Regulatory-Existing appeared to be related primarily to pre-1981 book-tax differences. In my analysis I have considered those amounts to be protected, but NW Natural should provide further information in testimony about what those balances represent.

Balances listed under Utility Other in the amount of $14,984,079 appeared to all be unprotected balances. I further adjust these amounts to remove approximately $768,981 (dr) of EDFIT associated with accrued vacation.

Finally, there was a $18,052,963 EDFIT balance, which NW Natural proposed to exclude from utility results related to Gill Ranch. Not being familiar with that facility, it is not clear to me whether those gains should be included in utility results. Further information from the Company on the Gill Ranch amounts is therefore necessary.

Q. HAS NW NATURAL PROPOSED TO EXCLUDE RECOGNITION OF EDFIT AMOUNTS IN RATES?

A. Yes. In response to NWIGU Data Request 42, NW Natural confirmed that it has did not include any amortization associated with EDFIT in results. NW Natural attempted to conflate the issue by pointing out that it did not revalue ADIT as a result of the TCJA. That revaluation makes no difference to results, however, since it is offset entirely by the new EDFIT liability. The rate base impacts of EDFIT are gradual overtime as the EDFIT amount amortizes in results. It is the impact of the amortization of the EDFIT that produces the primary impact on results.

Q. CAN THE COMMISSION EXCLUDE RECOGNITION OF THE EDFIT AMORTIZATION WITHOUT VIOLATING IRS NORMALIZATION REQUIREMENTS?

A. No. Establishing cost of service rates which exclude recognition of Excess Tax Reserves in the manner described § 13001(d) of the TCJA would violate the IRS normalization requirements. Thus, my understanding is that the Commission must establish rates that take into consideration the amortization of EDFIT in results, at least for protected plant ADFIT balances. In response to NWIGU Data Request 42, Subpart b, NW Natural stated that it believed it was able to exclude recognition of the EDFIT amortization, and still be in compliance with the normalization requirements. I disagree. If NW Natural plans to use the average rate assumption method ("ARAM") to reverse the EDFIT entries, the corresponding income statement effects have to be considered. Otherwise, NW Natural is not actually implementing the ARAM method.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. I have detailed my calculation of this adjustment in AWEC/203. Most utilities that rely on theoretical depreciation reserve calculations do not track assets by vintage in order to use the ARAM method. Notwithstanding, utilities have developed a number of methods to estimate the vintage date and use a methodology that resembles the ARAM method. In my calculation I have used a composite rate method, which reverses plant ADFIT balances at the composite depreciation rate for those balances from NW Natural's latest depreciation study. For non-protected balances, I propose a four-year amortization, which corresponds roughly to the period in which those underling book tax differences would reverse.

Within the revenue requirement model, the amortization amounts are post-tax, meaning the Company is not required to pay taxes on those gains. Accordingly, the EDFIT amortization must be grossed up for taxes and revenue sensitive costs to determine the revenue requirement effects. As demonstrated on AWEC/203, the result is amortization of $7,435,414. After considering the reduction to rate base that will occur through amortization of the EDFIT balance over the period 1/1/2018 through 10/1/2018, this amortization corresponds to a revenue requirement reduction of $13,497,754.

c. TCJA-3: Interim Period Deferral

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR ADJUSTMENT TCJA-3.

A. This adjustment represents a deferral for excess taxes collected over the interim period of January 1, 2018 through July 31, 2018. It relies on a simplified formula relying solely on rate base, and authorized return on equity. The formula can be performed without considering the utility's results, and thus, the formula is largely agnostic to the operating results in the test period.

Q. HOW HAVE YOU CALCULATED THE DEFERRAL FOR INTERIM PERIOD TAX SAVING?

A. As can be seen in Exhibit AWEC/204, I calculated two components of the interim period deferral. First, I determine the impact of restating the tax expense in results over the Deferral Period. Second, I determine the impact of amortizing the EDFIT gains over the deferral period, using the same amortization amount detailed for TCJA-2 above.

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

A. A higher-level approach was used for determining the over collection of tax expense in the deferral period. My approach estimates the tax impact on current rates based on the Cascade's 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.[2] The difference represents the estimate the revenue requirement savings associated with the lower rate.

Q. WHAT AMORTIZATION PERIOD DO YOU PROPOSE?

A. I propose a two-year amortization period for the TCJA deferral. I have selected that period because it would encourage NW Natural not to file a rate case within two years.

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

Q. SHOULD THIS INTERIM PERIOD DEFERRAL BE RETURNED THROUGH A SURCHARGE?

A. No. I recommend that the amortization occur in base rates, rather than through a separate surcharge. Use of a surcharge is problematic because it would single out the impact of the amortization, without recognizing that many other aspects of revenue requirement will have changed subsequent to the test period.

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 include an amount of estimated accrued interest at NW Natural's pre-tax cost of capital over the amortization period. Further, I recommend adopting a levelized amortization schedule that brings the balance to zero over the two-year period. That calculation may be seen on Page 2 of AWEC/204.

Q. DID YOU ASK NW NATURAL TO ESTIMATE THE IMPACT OF THE LOWER TAX RATE ON THE REVENUE REQUIREMENT IN ITS MOST RECENT RATE CASE?

A. Yes. In NWIGU Data Request 43, NW Natural was requested to provide its best estimate of the impacts of the TCJA on the revenue requirement approved in the 2012 general rate case. NW Natural objected to the request and responded that it does not have an estimate.

Q. IS IT APPROPRIATE FOR AN EARNINGS TEST TO BE APPLIED TO THIS AMOUNT?

A. No. Since the deferral is a benefit to ratepayers, an earnings test should not be applied to the deferral related to the interim TCJA tax benefits.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF THIS RECOMMENDATION?

A. The deferral calculation detailed in AWEC/204 suggests that NW Natural will over collect tax expenses by $19,718,520, including amortization of EDFIT balances over the interim period.

Based on the amortization schedule detailed on Page 2 of AWEC/204, I calculate monthly amortization of 641,345 or annual pre-tax amortization of $7,696,140. This level of amortization producing a revenue requirement reduction of $7, 916,553 after considering revenue sensitive costs.

d. <u>TCJA-4: Conversion Factor</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE FINAL ADJUSTMENT YOU PERFORMED WITH RESPECT TO THE TCJA-4?

A. This adjustment details the impact of the conversion factor. The adjustment effectively represents the tax impacts associated with the revenue sufficiency or deficiency amount. Application of this aspect of the TCJA change is relatively mechanical within the revenue requirement calculation.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. The impact is an approximate $1,571,723 reduction to revenue requirement in my model. Since this adjustment represents the incremental taxes on the revenue sufficiency or deficiency amount, the order of operation is particularly impactful with this adjustment. Thus, the impact will be different depending on the order that it is applied in the revenue requirement calculation and the overall level of revenue sufficiency or deficiency.

IV. CAPITAL EXPENDITURE

Q. WHAT ISSUES HAVE YOU IDENTIFIED WITH RESPECT TO NW NATURAL'S CAPITAL FORECAST?

A. I have performed a review of several capital expenditure items that NW Natural has proposed to include in rate base. I have also attempted to review NW Natural's methodology for forecasting, non-discrete capital items, although NW Natural did not provide sufficient information to review that aspect of its filing.

Q. HOW DOES NW NATURAL FORECAST CAPITAL EXPENDITURES?

A. NW Natural described its forecasting methodology generally in response to NWIGU Data Request 45. Effectively, NW Natural forecasts two distinct categories of capital expenditures. First, NW Natural identified a number of discrete projects that it expects to place into service in the forecast period. A few of those discrete projects were identified in the Direct Testimony of Mr. Karney. Second, in addition to the discrete projects, NW Natural adds another layer of capital expenditures, which are unrelated to any discrete project. These amounts represent additional capital that NW Natural believes it will spend but that cannot be attributed to any particular project.

a. Rate Base Measurement Date

Q. HOW DOES NW NATURAL PROPOSE TO MEASURE RATE BASE?

A. NW Natural has developed a capital forecast starting with plant balances as of November 1, 2017. It then developed a schedule of expected capital expenditures over the period November 1, 2017 through October 31, 2019. Using that schedule, NW Natural proposed to calculate its rate base on average of monthly balance over the period November 1, 2018, through October 31, 2019.

Q. DO YOU AGREE WITH THAT MEASUREMENT DATE?

A. No. Including plant additions in rates which are not expected until a distant period in the future runs too far afield of the known and measurable and used and useful standards to be appropriately considered in rates. My understanding is that rates must be based on plant that is used and useful under Oregon law. If the capital is not forecasted to be in service by the rate effective date, the capital should not be included in rates. Further, given the distant timing of the in service dates, ratepayers do not have any way to verify that the capital is actually placed into service, or the prudence of the underlying expenditures.

Q. WHAT DO YOU PROPOSE?

A. I recommend that NW Natural be required to use a rate base measurement no later than the rate effective date of November 1, 2018. That is similar to what PGE has proposed in its most recent rate case, UE 335, and there is no reason why a similar approach is not appropriately applied in this case.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. I relied on NW Natural's response to Staff Data Request 128, Attachment 2, to calculate the impact of this adjustment. I adjusted rate base by eliminating the incremental net plant in NW Natural's forecast beyond November 1, 2018. Further, I estimated the impact on depreciation expense, based on the incremental plant balances that were removed. Removing the incremental capital and reserves beyond the rate effective date results in an $37,322,630 reduction to rate base and a corresponding $112,511 reduction to depreciation expenses. The result is a 3,898,295 reduction to revenue requirement relative to NW Natural's initial filing.

b. <u>Non-Discrete Capital Additions</u>

Q. HOW DOES NW NATURAL FORECAST CAPITAL ADDITIONS FOR NON-DISCRETE CAPITAL PROJECTS?

A. In a March 5th, 2018 technical workshop, NW Natural indicated that it uses a model called UI System Planner to forecast capital expenditures for non-discrete capital items, which cannot be tied to any identifiable project. As deployed by NW Natural, the model used plant balances as of October 31, 2017, and applied some form of escalation factors to forecast an amount of expenditures which cannot be tied to any particular project. In the workshop, NW Natural mentioned that the factors input into the model were calculated in Excel based on historical trends associated with capital expenditures.

Q. DID YOU REQUEST NW NATURAL PROVIDE THE WORKPAPERS SUPPORTING THE FACTORS INPUT INTO THE UI SYSTEM PLANNER?

A. Yes. In NWIGU Data Request 19, NW Natural was requested to provide the workpapers that it used to support the capital expenditure rates into the UI System Planner model. NW Natural, however, did not provide those workpapers in its response. Instead, it provided a link to the website for the company that developed the UI System Planner model. No information could be gleaned from that website site, however, about the calculations involved in forecasting capital additions in the UI System Planner model, let alone the modeling methodologies NW Natural used to forecast its specific capital expenditure proposal.

Q. DID YOU ISSUE A FOLLOW-UP REQUEST?

A. Yes. In NWIGU Data Request 45, NW Natural was again requested to provide further information on how it forecasted non-discrete capital additions. The Company provided a more detailed response, but it did not provide any useful information to review its forecast of capital expenditures for non-discrete capital items. For example, in attachment NWIGU DR 45 Attachment 1, NW Natural provided inputs into the model that were used to determine the percentage of capital expenditures that close to plant each month. Those factors, however, were not meaningful in determining the level of capital expenditures in any particular month, just the portion that closed to plant. It was also not clear how those close-to-plant factors were being applied.

Further, when asked for historical capital expenditure data, the data provided in NWIGU DR 45, Attachment 3, had no nexus to the forecast values input that were into the model. The forecast values were provided in NWIGU DR 45, Attachment 2.

Q. HAS NW NATURAL PROVIDED SUFFICIENT INFORMATION TO REVIEW THE NON-DISCRETE EXPENDITURES?

A. No. NW Natural has repeatedly not provided the information necessary to support the level of non-discrete capital additions in the test period. Referring to the results of a black box model, for a type of analysis that is typically performed in a spreadsheet, is not adequate to demonstrate whether those expenditures are appropriate. NW Natural did not provide the UI System Planner model to intervenors. The algorithms involved in the model are also unknown, and therefore, there is no way to understand how the model developed the forecast.

Q. WHY ARE THESE NON-DISCRETE ADDITIONS IMPORTANT?

A. NW Natural has proposed a staggering level of capital in the forecast period. Based NWIGU DR 45, Attachment 3, actual plant additions were $100,470,148 in 2015, $118,063,680 in 2016 and $141,566,682 in 2017. In contrast, the UI planner model forecasts plant additions of $203,542,156 in 2018. Assuming a 43% increase to capital expenditures is not a reasonable assumption, and a key driver appears the non-discrete capital items. By performing its forecast with both discrete and non-discrete capital items, there is no objective standard that can be applied to determine whether the non-discrete forecast is reasonable. If NW Natural were to identify each and every project as a discrete item in the forecast period, there would be no need for an adjustment for non-discrete items. Thus, there is no way to know if NW Natural is double counting by capturing expenditures both as discrete and non-discrete items.

Q. WHAT DO YOU PROPOSE?

A. Because NW Natural failed to provide the information necessary to support the non-discrete capital additions, I propose remove those amounts from rate base. Since the non-discrete additions subsequent to the rate effective date of October 31, 2017 were removed in the prior adjustment related to the rate base measurement date, this adjustment only applies to the non-discrete capital additions forecast over the period January 1, 2018 through October 1, 2018.

Q. WHAT IS THE IMPACT OF EXCLUDING THIS ADJUSTMENT?

A. Based on NW Natural's response to NWIGU Data Request 45, $99,229,409 of capital additions were forecast over the period January 1, 2018 through October 1, 2018. It is also necessary to exclude incremental depreciation, depreciation reserves. A further adjustment for deferred taxes associated with these amounts is also necessary, but I did not include that portion of the adjustment since I did not have the data to calculate those impacts, which I expect to be relatively small. After making those adjustments, the result is an $97,995,442 reduction to rate base and a $1,962,948 increase to net operating income. The revenue requirement impact is approximately $12,697,740

c. <u>Mid-Willamette Feeder Project</u>

Q. PLEASE PROVIDE SOME BACKGROUND ON THE MID-WILLAMETTE FEEDER PROJECT?

A. The Mid-Willamette Feder Project was originally proposed in rate base in the 2012 general rate case. In that proceeding Staff and parties demonstrated that the project was not necessary and for that reason should be excluded from rate base. The Commission agreed and disallowed the investment.

Q. WHAT DOES NW NATURAL PROPOSE IN THIS CASE?

A. NW Natural proposes to include the previously disallowed investment in rate base in this matter.

Q. HAS NW NATURAL PRESENTED ANY NEW INFORMATION TO JUSTIFY INCLUDING THE MID-WILLAMETTE FEEDER IN RATE BASE?

A. No. NW Natural simply reiterates the same arguments that it made in the 2012 general rate case.

Q. IS THE MID-WILLAMETTE FEEDER APPROPRIATELY INCLUDED NOW?

A. No. In the 2012 GRC it was determined that the Mid-Willamette feeder was not needed until 2025. Since the Company's load have not so significantly in the Albany Corvallis region to justify including the Mid-Willamette feeder in rates today.

Q. IS THE MID-WILLAMETTE FEDER NEEDED FOR RELIABILITY PURPOSES?

A. No. As the Commission noted in the 2012 GRC, Albany-Corvallis area was a single-feed system since at least 1931 and that customers have not experienced unreliable service on the system at any point during this entire period. The area connects to the Northwest Pipeline, with a relatively short lateral. Effectively, reliability would only be a concern in this area if there was a disruption on the Northwest Pipeline. If there were such a disruption, however, the fact that the area is no longer a single feed system would likely not avoid any service disruption.

Q. WHAT DO YOU RECOMMEND?

A. Since the project is currently in service there is no way to go back in time to determine the actions that NW Natural should have taken at the time it constructed the Mid-Willamette Feder project. Accordingly, I recommend that the disallowance from the 2012 GRC stand and that NW Natural not be allowed to include the Mid-Willamette Feeder in rate base.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. Based on the amount reported in NW Natural's testimony, removing the Mid-Willamette Feeder results in an approximate $20,200,000 reduction to rate base. I have modeled that amount as a rate base deduction in Exhibit AWEC/202. Further refinements to this amount are necessary to consider depreciation expenses and to clarify whether the amount includes ADIT associated with the project. Based on my modeling, removing the Mid-Willamette Feder resulting in a $2,047,223 revenue requirement reduction.

d. <u>Corvallis Loop Project</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE CORVALLIS LOOP PROJECT.

A. The Corvallis Loop Project is a segment of 12-inch, high-pressure pipe that runs between Corvallis and Albany. The Corvallis Loop Project was initiated in 2011, and after significant delays and budget overages, was completed in 2013.

Q. HAVE YOU REVIEWED THE CLOSE-OUT REPORT FOR THE CORVALLIS LOOP PROJECT?

A. Yes. In response to OPUC Data Request 200, NW Natural provided the close out report for the Corvallis Loop project. I have attached that document as Exhibit AWEC/205. It shows that the project was plagued with mis-management, poor planning, and lackluster execution.

Q. WERE THE COST ASSOCIATED WITH THE CORVALLIS PROJECT PRUDENTLY INCURRED?

A. No. It is not necessary to restate here all of the issues identified in the project close out report in AWEC/205. Those issues speak for themselves. Based on my review of that document, however, I have concluded that, at a minimum, the budget variances that NW Natural experienced were not prudent costs and are not appropriately included in results. I am also concerned that, as an extension of the Mid-Willamette Feeder, the entirety of this project should be excluded.

Q. WHAT WAS THE ORIGINAL BUDGET FOR THE CORVALLIS LOOP PROJECT?

A. The project was originally expected to cost $17,703,000,[3] including construction overhead and allowance for funds used during construction.

Q. WHAT WAS THE FINAL COST FOR THE CORVALLIS LOOP PROJECT?

A. Due to numerous problems and delays that were encountered with the Corvallis Loop Project, the ultimate capital cost was $28,021,994, including construction overhead and allowance for funds used during construction. This represented a budget variance of $10,318,994 or 58.3% of the original budget request.

Q. WHAT IS THE IMPACT OF ELIMINATING THE BUDGET VARIANCE?

A. After considering accumulated depreciation, as well as removing incremental depreciation expenses, the impact of eliminating the 36.8% budget variances is an approximate $858,965 reduction to revenue requirement. If the entire project is excluded on the basis that the Corvallis Loop is an extension of the Mid-Willamette Feeder Project, the result is a $2,332,358 reduction to revenue requirement.

e. <u>SE Eugene Project</u>

Q. WHAT IS THE SE EUGENE PROJECT?

A. The SE Eugene project is a new 12-inch high pressure pipeline that extends west from the existing South Eugene Gate and terminates at the connection to the existing 6" steel distribution main at Hilyard Avenue and near 30th Street. The project charter was provided in response to NWIGU Data Request 22 and has been attached as AWEC/206.

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3 AWEC/205 at 3.

Q. HOW MUCH CAPITAL WAS FORECAST IN NW NATURAL'S INITIAL FILING FOR THE SE EUGENE PROJECT?

A. There are a number of conflicting estimates. On page 29 of the Direct Testimony of Mr. Karney, NW Natural states that the cost of the SE Eugene project is estimated to be $4.5 million. Further, in response to NWIGU Data Request 22, sub-request d., NW Natural stated that the current capital estimate of the SE Eugene project was $4.8 million.

Q. ARE THOSE AMOUNTS CONSISTENT WITH THE AMOUNTS INPUT INTO UI SYSTEM PLANNER?

A. No. Based on the amounts reported in NWIGU DR 45, Attachment 2, NW Natural actually included $6,098,119 of capital related to the SE Eugene Project, significantly more than the amount it represented in testimony. That amount was also assumed to be placed into service in August 2018.

Q. HAS THE SE EUGENE PROJECT BEEN DELAYED?

A. Yes. In response to NWIGU DR No. 22, NW Natural stated that it believed the project will be completed on September 30, 2018, later than the date modeled in the UI System Planner.

Q. HAS THE COMPANY STARTED CONSTRUCTION ON THE SE EUGENE PROJECT?

A. As noted in response to NWIGU DR No. 22, NW Natural has not started construction of the SE Eugene Project.

Q. IS THERE ENOUGH TIME TO INCORPORATE THE SE EUGENE PROJECT INTO REVENUE REQUIREMENT?

A. No. Even if NW Natural were successful in achieving its September 30, 2018 online date, there is not enough time to properly review the project for inclusion in rate base in this proceeding. At that point the evidentiary portion of this proceeding will have long passed.

Given that it has not even begun construction, there is nothing to suggest whether the project will be placed into service by the rate effective date in this matter.

Q. WHAT DO YOU RECOMMEND?

A. I recommend excluding the SE Eugene project from rate base. The impact is an approximate $743,920 reduction to revenue requirement.

V. OTHER REVENUE REQUIREMENT ISSUES

a. Stock Issuance Cost

Q. WHAT EQUITY ISSUANCE COSTS HAS NW NATURAL INCLUDED IN REVENUE REQUIREMENT?

A. NW Natural has proposed to include stock issuance costs of $1,198,454 in revenue requirement. This amount was calculated by taking the average amount of stock issuance costs experienced over the period 2016 through 2018. Of those three years, 2016 was the only year with stock issuance costs of $4,120,800, on a total Company basis.

Q. WHAT TYPE OF EXPENDITURES WERE INCLUDED IN THE $4,120,800 AMOUNT?

A. In response to OPUC Staff DR 192, NW Natural provided detail of this amount. The amount consisted of $2,074,600 in underwriting fees, $1,588,840 in issuance discounts, $303,801 in accounting and legal fees, and $144,042 in fees.

Q. ARE THESE AMOUNTS APPROPRIATELY REFLECTED IN RESULTS OF OPERATIONS?

A. No. Stock issuance costs are not appropriately considered in results for several reasons. First, these amounts were all booked in 2016, and it would constitute retroactive rate making for NW Natural to be provided with recovery for those amounts. No deferral was issued with respect to the 2016 stock issuance. Second, stock issuance costs are not appropriately considered an expense. Both GAAP and tax accounting require stock issuance costs to be treated as a reduction in the proceeds of the stock sale. Stock issuance costs are considered the equivalent of selling the stock at a discount, and thus, those costs do not create an expense that is eligible for recovery through rates.

Q. HAS THIS ISSUE BEEN LITIGATED FOR PURPOSES OF TAX ACCOUNTING?

A. Yes. There are a number of cases where, for tax accounting, it has been established that a company could not deduct stock issuance costs against net operating income. Barbour Coal Co. v. Commissioner (74 F.2d 163) is an example of such a case.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF THIS ADJUSTMENT?

A. Removing the stock issuance costs results in a $1,232,777 reduction to revenue requirement.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL,	)
	)
Request for a General Rate Revision.	)

EXHIBIT 201 - MULLINS QUALIFICATIONS

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

April 20, 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 began performing independent energy and utility consulting in 2013 and 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 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.
- <u>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</u>, 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 344

	)
In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL,	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT 202 - REVENUE REQUIREMENTS CALCULATIONS

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS ON

BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

April 20, 2018

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

			Cumulative Results			Impact of Adjustments			
Line	**Adj. No.**	**Description**	Net Oper. Income	Rate Base	Rev. Req. Def. / (Suf.)	Pre-Tax Net Oper. Income	Net Oper. Income	Rate Base	Rev. Req. Def. / (Suf.)
1		**NW Natural Initial Filing**	**60,005**	**1,189,882**	**52,446**				
Cost of Capital Adjustments									
2	A1	Return on Equity (9.15%)	60,005	1,189,882	43,796				(8,651)
Misc. Tax Issues									
3	A2	ADIT - Accrued Vacation	60,005	1,187,849	43,545	-	-	*(2,032)*	(250)
4	A3	R&D Tax Credit	60,049	1,187,849	43,470	-	*44*	-	(75)
TCJA Adjustments									
5	TCJA-1	Restate Tax Expense	67,794	1,187,849	30,205	-	7,745	-	(13,265)
6	TCJA-2	Excess Deferred Taxes	75,230	1,181,653	16,707	-	7,435	(6,196)	(13,498)
7	TCJA-3	Interim Period Deferral	79,852	1,181,653	8,791	7,696	4,622	-	(7,917)
8	TCJA-4	TCJA Conversion Factor	79,852	1,181,653	7,233	-	-	-	(1,558)
Capital Adjustments									
9	A4	Rate Base Cut-Off	79,934	1,144,331	3,334	113	82	(37,323)	(3,898)
10	A5	Non-Discrete Capital	81,897	1,046,335	(9,363)	2,689	1,963	(97,995)	(12,698)
11	A6	Mid-Willamette Feeder Project	81,897	1,026,135	(11,410)	-	-	(20,200)	(2,047)
12	A7	Corvallis Loop Project	82,039	1,019,640	(12,269)	195	142	(6,495)	(859)
13	A8	SE Eugene Project	82,127	1,013,512	(13,013)	119	87	(6,128)	(744)
Other Adjustments									
14	A9	Stock Issuance Costs	83,001	1,013,512	(14,246)	1,198	875	-	(1,233)
15	A10	Interest Synch	81,755	1,013,512	(12,490)		(1,246)		1,756
					Total Adjustments:	***12,011***	***22,996***	***(176,370)***	***(66,693)***

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL,	)
	)
Request for a General Rate Revision.	)

EXHIBIT 203 - RESTATED TAX EXPENSE CALCULATION

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS ON

BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

April 20, 2018

Northwest Natural Gas Corporation
TCJA-1: Calculation of Excess Deferred Federal Income Taxes
In Thousands

		Per Initial Filing		Adjusted Per TCJA	
		TEST YEAR		TEST YEAR	
Line No.		State Taxes (c)	Federal Taxes (d)	State Taxes (c)	Federal Taxes (d)
1	Operating Revenues	$642,157	$642,157	$642,157	$642,157
2	Operating Revenue Deductions	427,211	427,211	427,211	427,211
3	Property & Other Taxes	45,696	45,696	45,696	45,696
4	Book Depreciation	73,605	73,605	73,605	73,605
5	Interest (Rate Base * Cost of Debt)	31,133	31,133	31,133	31,133
6	Remove Equity Flotation	(1,198)	(1,198)	-1,198	-1,198
7	State Tax Deduction	0	5,500	0	5,500
8	Subtotal	65,710	60,210	65,710	60,210
9	Permanent Differences 1/	6,652	5,965	6,167	5,655
10	Taxable Income	72,362	66,176	72,362	66,176
11	Tax Rate	7.60%	35.00%	7.60%	21.00%
12	Tax Before Credits	5,500	23,161	5,500	13,897
13	Credits (R&D)	0	(76)	0	(76)
14	Total Tax	$5,500	$23,085 (a)	$5,500	$13,821 (b)
				Delta (b) - (a):	-9,265
				Less: Decoupling Impact	1,519
				Total Adjustment	-7,745

1/ Federal Permanent Differences allocated using depreciation factor

Northwest Natural Gas Corporation
TCJA-2: Calculation of Excess Deferred Federal Income Taxes
In Thousands

Company	No.	Acct.	Account Description	Gross Balance	Original Measurement	Remeasured	EDIT Balance	OR Allocated	Amort. Rate	EDFIT Amort.
Northwest Natural Gas Company	5000	283016	DEF INC TAX-PRE 1981 OR FAS 109	(34,787,377)	(34,787,377)	(19,138,932)	(15,648,445)	(15,648,445) *	2.71%	(424,073)
Northwest Natural Gas Company	5000	283061	DEF INC TAX-UTIL-DEPREC-FED	(1,093,758,304)	(356,970,637)	(214,182,382)	(142,788,255)	(126,270,885) *	2.71%	(3,421,941)
Northwest Natural Gas Company	5000	283071	DEF INC TAX-UTIL-OTHER-FED	(114,990,835)	(39,249,447)	(23,549,668)	(15,699,779)	(14,357,602)	25.00%	(3,589,401)
			Total	(1,243,536,516)	(431,007,461)	(256,870,982)	(174,136,478)	(156,276,932)		(7,435,414)
								Accum Amort 1/1/2018-10/31/2018:		(6,196,179)

* Composite Depreciation Rate

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

In the Matter of	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL,	)
Request for a General Rate Revision.	)

EXHIBIT 204 - INTERIM PERIOD DEFERRAL CALCULATION

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS ON BEHALF

OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

April 20, 2018

Northwest Natural Gas Corporation

TCJA-3: Calculation of the Deferral Related to Excess Taxes Collected in Rates Over the Period January 1, 2018 through October 31, 2018

In Thousands

Line				
1	**Restating Adjustment Calculation Using Gross-up Method:**			
2	Rate Base	Un-adjusted Base Year	$1,088,556	
3	Equity %		50.00%	
4	Equity Portion of Rate Base	Line 2 * Line 3	544,278	
5	Return On Equity	2012 GRC	9.40%	
6	Pretax Return On Equity (35% Rate)	Line 5 * (1 - 39.9%	15.65%	
7	Pretax Equity Returns Required (35% Rate	Line 4 * Line 5	85,185.05	
8	Pretax Return on Equity (21% Rate)	Line 7 * (1 - 27.0%	12.88%	9.06%
9	Pretax Equity Return (21% Rate)	Line * Line 7	70,088.97	
10	**Annual Equity Return Differential (35% to 21% Rate)**	Line 9 * Line	**(15,096)**	
11	Less Incremental Revenues on permanent Differences		835	
12	R&D Creidt		11	
13	**Deferred Tax Expense**		**(14,250)**	

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**	**Total**
14	**Monthly Deferral Calculation**												
15	Monthly Return Diff. at Restated 21 % Tax Rate	Line 10 / 12	(1,188)	(1,188)	(1,188)	(1,188)	(1,188)	(1,188)	(1,188)	(1,188)	(1,188)	(1,188)	(11,875)
16	Monthly EDFIT Amortization	Tab 11	(620)	(620)	(620)	(620)	(620)	(620)	(620)	(620)	(620)	(620)	(6,196)
17	Monthly EDFIT Amortization (Pretax)	Line 16 / (1-21%)	(784)	(784)	(784)	(784)	(784)	(784)	(784)	(784)	(784)	(784)	(7,843)
18	Total Deferred Amounts	Line 16 + Line 17	(1,972)	(1,972)	(1,972)	(1,972)	(1,972)	(1,972)	(1,972)	(1,972)	(1,972)	(1,972)	(19,719)
19	Carrying Charge (Per Mo. at Pre-tax ROR)		0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	
20	Balance												
21	Beginning Balance		-	(1,972)	(3,944)	(5,916)	(7,887)	(9,859)	(11,831)	(13,803)	(15,775)	(17,747)	
22	Deferral	Line 18	(1,972)	(1,972)	(1,972)	(1,972)	(1,972)	(1,972)	(1,972)	(1,972)	(1,972)	(1,972)	
23	Interest	Line 19 * (Line 20 + Line 21 / 2)	(7)	(22)	(37)	(52)	(67)	(82)	(97)	(112)	(126)	(141)	
24	Ending Balance	∑ Lines 21:23	(1,972)	(3,944)	(5,916)	(7,887)	(9,859)	(11,831)	(13,803)	(15,775)	(17,747)	(19,719)	

Northwest Natural Gas Corporation

TCJA-3: Deferral Amortization for Excess Taxes Collected in Rates Over the Period January 1, 2018 through July 31, 2018

In Thousands

Month	Beg Balance	Amortization	Interest Rate	Interest	Ending Balance	
5/1/2018	(13,803)	**641**	0.75%	(114)	(13,275)	
6/1/2018	(13,275)	*641*	0.75%	(110)	(12,744)	
7/1/2018	(12,744)	*641*	0.75%	(106)	(12,208)	
8/1/2018	(12,208)	*641*	0.75%	(102)	(11,669)	
9/1/2018	(11,669)	*641*	0.75%	(98)	(11,125)	
10/1/2018	(11,125)	*641*	0.75%	(94)	(10,578)	
11/1/2018	(10,578)	*641*	0.75%	(89)	(10,026)	
12/1/2018	(10,026)	*641*	0.75%	(85)	(9,470)	
1/1/2019	(9,470)	*641*	0.75%	(81)	(8,910)	
2/1/2019	(8,910)	*641*	0.75%	(77)	(8,345)	
3/1/2019	(8,345)	*641*	0.75%	(73)	(7,776)	
4/1/2019	(7,776)	*641*	0.75%	(68)	(7,203)	
5/1/2019	(7,203)	*641*	0.75%	(64)	(6,626)	
6/1/2019	(6,626)	*641*	0.75%	(60)	(6,044)	
7/1/2019	(6,044)	*641*	0.75%	(55)	(5,458)	
8/1/2019	(5,458)	*641*	0.75%	(51)	(4,868)	
9/1/2019	(4,868)	*641*	0.75%	(46)	(4,273)	
10/1/2019	(4,273)	*641*	0.75%	(42)	(3,674)	
11/1/2019	(3,674)	*641*	0.75%	(37)	(3,070)	
12/1/2019	(3,070)	*641*	0.75%	(33)	(2,461)	
1/1/2020	(2,461)	*641*	0.75%	(28)	(1,848)	
2/1/2020	(1,848)	*641*	0.75%	(24)	(1,230)	
3/1/2020	(1,230)	*641*	0.75%	(19)	(608)	
4/1/2020	(608)	*641*	0.75%	(14)	19	<-Goal Seek to Zero
Annual Amortization (Pre-tax):		**7,696**				

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL,	)
	)
Request for a General Rate Revision.	)

EXHIBIT 205 - CORVALLIS REINFORCEMENT

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

April 20, 2018

NW Natural
project management office

PROJECT CLOSEOUT

Project Name: Corvallis Loop

Project Number: 200363

Tier: III - 2014

Date: 3-10-2014

Brian Konrad — 4/03/15

Brian Konrad, Project Manager — Date

4/3/15

Steve Nelson, Engineering Director — Date

4/8/15

Jon Huddleston, Utility Operations Senior Director — Date

4/8/15

Grant Yoshihara, Executive Sponsor — Date

9/17/15

Shante Wilson, PMO Representative — Date

Sign Here

PROJECT DESCRIPTION
Install 10.2 miles of 12 ¾" X-52 pipeline from the Albany Feeder to OSU Energy Center/ Philomath Feeder.

PROJECT SCOPE
Original Scope
The scope of this project includes two phases. The first phase is for installation of approximately 12,700 feet of 12-inch steel natural gas pipeline tested and certified at a Maximum Allowable Operating Pressure (MAOP) of 720 psig. This pipeline will connect to the existing 10-inch Corvallis – Albany Transmission line (S22 pipeline) located on Riverside Drive in Linn County and extends south to State Highway 34. This section of pipeline will be designed to the parameters of the future Mid-Willamette Valley Pipeline in anticipation of future expansion north to the Perrydale Station (P30 pipeline) . Considerations for future pressure regulation will be provided at either end of the pipeline. The second phase is for installation of approximately 39,300 feet of 12-inch steel natural gas pipeline tested and certified at a MAOP of 400 psig. This pipeline will connect to the first phase pipeline at State Highway 34 and extend west to the S-26 Philomath Feeder at Oregon State University located on SW 35th Avenue in Corvallis, Oregon.
Revised Scope
The installation length increased from 9.8 miles to 10.2 miles due to route restrictions with landowners and sensitive areas. There was three additional pressure reduction regulators installed. 1. Western and Stamm Place, 2. Knife River and 3. Cushman and HWY 34.

PROJECT SCHEDULE			
Original Start Date	June 2011	Actual Start Date	June 2012
Original End Date	October 2011	Actual End Date	October 2013
Schedule Variance Explanation			
The project experienced a schedule change due to land use permitting, lengthy land owner negotiations, Cultural Resource studies and changes in design.			

PROJECT BUDGET With COH & AFUDC			
	Original Budget	**Actual Budget**	**Variance**
Capital	$17,703,000	$ 28,021,994	$ 10,318,994
Change Order 1	$ 9,048,931		
Change Order 2	$ 1,107,519		
VOH		$ 352,757	
Total	$ 27,859,450	$ 28,374,751	$ 515,301

Budget Variance Explanation

SEE TABLE ON PAGE 16 for Financials without COH

Two Change Orders: **See Project Challenges**

Change Order One: $ 9.1 million –

1. Design Cost $ 1.2
2. Land Acquisitions $ .8
3. Increase in installation methods $ 5.2
4. Increases in Bore footages $ .3
5. Increases in materials $ .6
6. Increase in project OH $ 1.0

Change Order Two: $ 1.1 Million

Contractor prices on HDD bores were 40% over estimated values.

DELIVERABLES
Original Deliverables
• Install 12,700 feet of 12-inch steel natural gas pipeline tested and certified at a MAOP of 720 psig. • Install 39,300 feet of 12-inch steel natural gas pipeline tested and certified at a MAOP of 400 psig. • Rebuild the gas supply meter set at the OSU Energy Center and tie the existing service over to the new 12-inch (400 MAOP) pipeline. • Install a new district regulator at SW 35th Avenue and Washington Way and connect the new 12-inch (400 MAOP) pipeline to the existing 6-inch (225 MAOP) Philomath pipeline.
Revised Deliverables
• Installed additional District regulators at Hwy 34 and Cushman, Hwy 34 and Knife River, Western Ave and Stamm Pl. • Installed an additional 1,856 feet of 12" due to route changes to avoid sensitive cultural resource impacts • Constructed the pipeline in multiple phases

OBJECTIVES:
The project will provide additional supply reinforcement to Corvallis/Philomath service areas and increase the delivery of gas capacity to the Mid-Willamette area. Although the project will provide improved service to area customers in the short term, multiple system improvements still need to be considered for long term system reliability.

OPEN OUTSTANDING ISSUES

PROJECT CHALLENGES

The Corvallis Loop Project had several challenges in Permitting ,Land Acquisition and Construction:

- The WH Pacific route evaluation contract did not include permitting due diligence for cultural resource permitting.
- The permitting requirements for installing a utility facility in agricultural lands required land owner acknowledgement and approval within Linn Co. We had one land owner which held out signing the acknowledgement documents until the easement documents were reviewed by outside Attorneys. This delayed all permitting within Linn County. The delays in permitting are a contributing factor to the Change Order 1.
- We had not known about the Land Use requirements when we originally developed the scope, schedule and estimate for the project. We had consultants working on obtaining the required signatures but the deliverable just could not be met in time for construction in 2011.
- NWN was unable to fulfill the requirements of the Cultural Resource requirement of the Army Corp/ DSL permit. This resulted in segmenting the project into three phases. Phase 2 constructed in 2012, Phase 3(Corvallis) in 2012 and Phase 1 and the remaining segments of Phase 3 in 2013. The need to move from phase to phase was a contributing factor in Change Order 1.
- The process of securing a route across the Willamette River into Corvallis included a long negotiation with The City of Corvallis. We proposed four routes and finally reached agreement to install the pipeline crossing within the City of Corvallis Parks properties. This process exhausted our design budget and is a contributing factor to Change order 1.
- The design of the Willamette/ Marys River bore was 6454 ft. in length. This activity was of very high risk due to soft fatty clays, a pilot hole intersect bore and the alignment was adjacent to the Hwy 20 bridge structures. NWN successfully installed the bore but had a release of bore fluids into the Marys River. This event stopped drilling activity and was reportable to the Army Corp/DSL, DEQ and ODFW. The agencies required full removal of the release into the States waters. NWN responded promptly to the event and the clean-up was successful. NWN avoided any monetary fines but did receive a Warning Letter from DEQ.

Project Challenges

- Geological formations were a major challenge for the project. The project is located within the Willamette River floodplain and the subsurface composition is made up of loose gravels over fatty soft clay. These conditions made trench profiles unstable and required excessive backfill quantities. This situation initiated a change order by Henkels and McCoy to NWN for the sum of $ 32,000.00.
- The loose gravels in bore 5 of phase 2 created a need for another change order that required splitting the bore into two segments. The end result was $ 80,563.00 change order for rebuilding the bore strings.
- The construction for the 2012 Phase (2) - 4 mile installation tie in was located at Knife River Aggregate and Hwy 34. This tie in was a cost of $ 85,844.05 that was an extra to the original deliverables of the contract.
- The phase (3) construction on HWY 20 had a 26 foot deep excavation that was outside unit cost that resulted in a $ 276,707 change order. We obtained permits late in 2012 and desired to construct the Philomath feeder to HWY 20 pipe segment to tie to the Willamette River Bore.
- The traffic control requirements for the Phase 3 work cost an additional $ 29,672.00. This requirement was due to the fact that OSU football was in session and additional resources were required by the permitting agencies, The City of Corvallis and OSU.
- Summary for 2012- NWN installed 50% of the project and consumed 93% of the original budget.
- Revisions in estimates and forecasting for 2013 construction required a Change Order request to the Executive staff for the sum of $ 9 million. This request was approved.
- Results from the 2013 RFP process for the remaining HDD bores produced unit cost that exceeded the revised estimate. Another change request was presented and approved for $ 1.1 million.
- The total budget was increased to $ 27.8 million. The project has been closed out within 5% of the adjusted budget.

LESSONS LEARNED

Safety

Attendees: Leslie Kantor, Ken Semore and Brian Konrad

What went well?

1. The design process produced a route that had safety as a first priority.
2. Traffic Control Plans were effective for the project. They were designed by K&D Services using a pre- permitting meeting with ODOT and NWN Engineering team.
3. K&D Services had a dedicated lead person for the project to make sure that the TCP (Traffic Control Plan) was executed to ensure a safe work zone and meet the conditions of the ODOT permit.
4. The designed alignment for the pipeline was adjacent to overhead power lines and signs were created to caution the pipeline construction workers of the overhead hazard.
5. The Pipeline Contractor conducted documented daily tailgater meetings with specific task assigned to the craft workers. They then would identify the hazards associated and make sure that the appropriate resources were available to mitigate/minimize the risk to the workers and public.
6. The Pipeline Contractor had procedures in their Safety Plan for near misses and stopped work to gather the root cause to make necessary adjustments until a safe work environment was established.
7. Before we started the project a preconstruction meeting was conducted with Safety, Damage Prevention, ODOT, Environmental, Construction, Supply Chain, and Land &Risk with the Contractor. All expectations and questions were shared.
8. Having a Project Site Supervisor supporting the JSA (Job Safety Analysis) on the job enhances safety. The Leadership made sure that the daily assignments were identified and resourced to avoid risk to the workers and public.

Safety Continued

What we learned that needs improvement

1. We learned that we need to set the expectation that all workers need to wear high visibility clothing that is fire resistant.
2. NWN needs to establish a JSA (Job Site Analysis) process to identify hazards for the desired task.
3. NWN needs to have daily assignments clearly documented and evaluated to make sure that they have the hazards identified. NWN needs to have a resource plan to address hazards that are identified by the JSA.
4. NWN needs safety leadership on site to document near misses and assure hazard management is in place before the work process continues This is to include making sure that the TCP is executed, excavations are shored, PPE is issued, assignments are clearly identified with associated hazards and resourced appropriately for a safe work environment.
5. NWN needs to have protocols for time management on the project. Things to consider are common understanding of assignments, adequate resources, DOT requirements, safety plan and communication.

Environmental Team

Attendees: Mike Hayward Andy Bauer and Brian Konrad

What went well?

Overall it was commented that the Contract Crew and NWN Construction crews did a good job adhering to the conditions of the multiple permits required.

The use of water storage tanks is a good process for storing hydro test water.

The testing of domestic water wells went well and provided NWN with quality assurance of the HDD bores on the project.

The response to the inadvertent bore returns in the Marys River was well executed and communicated.

The responses to the Media of the events on the project were reviewed by the Environmental Manager to make sure we stated the consistent fact

What we need to improve on:

NWN needs more time in the future to apply for permits. We also need to conduct cultural resource due diligence work early to allow for the permitting long lead time.

NWN needs to apply for permits in full. This project was permitted in phases and created a lot of unnecessary work for the Environmental team.

We need to include the Environmental team in the pre-construction meetings with NWN crews. We do for the projects that we contact out. We need to have consistency in our processes.

We need a project check list to ensure best practices. For example include water well testing within 200' of the HDD bore.

Have domestic water wells identified and included in the design process for HDD bores.

Use another contractor for the Cultural Resource requirement. URS did not perform to NWN expectations. We are using HRA & Associates.

NWN needs to include NWN Horizontal Directional Drill Specification in all contract bore contracts.

NWN Environmental team needs to engage with training to make sure everyone knows the process for working on Agricultural lands.

NWN needs oversight on the projects to ensure expectations are met.

NWN needs to use someone other than WH Pacific for engineering services. WH Pacific received a 2 on a scale of 1-5.

NWN needs to have a project team like SMPE: Project Manager, Professional Engineer and Environmental Specialist. 12/09/2013

Supply Chain Management Team

Attendees- Ted Smart, Marty Borrevik, Craig Gagner, Jana Davis, Cliff Crawford and Brian Konrad

What Went Well?

The project met the revised deliverables of installing 10.5 miles of 12"

Vendors supported the project with above average rating of 4 on a scale of 1-5.

Vendor	GL	Rating	Notes
WH Pacific	505100	2	Use Others
Geo Engineers	505100	4	
Epic Land Solutions	505100	4	
Enviro Logic	505100	4	
URS	505100	1	Use Others
JTI	505100	4	
Jammies Environmental	505100	4	
HDD Co	502100	5	
Henkels & McCoy	502100	3	
Brothers	502100	4	
Alaska Continental	502100	3	
Brotherton Pipeline	502100	4	
K&D Services	502100	4	
Xylem	502100	3	

Vendor Survey Continued

Rain for Rent	502100	4
Water Truck Services	502100	4
JTI Supply	502100	4
Judd's Plumbing	502100	4
Fox Erosion	502100	4
Courtney and Sons	502100	4
Outdoor Fence	502100	3
Enduro Pipeline	502100	4
DPN	502100	4
Dennis Harding	502100	4
Sunbelt Rentals	502100	4
Ferguson	501400	4
Knife River	501400	4
Fore 4S	501400	4
McJunkin	501400	4
State Pipe	501400	4
Protection Engineering	501400	4

Supply Chain Management – Continued

What we need to improve on?

Projects in the future need to have adequate time to obtain a full permitting process to minimize change.

Projects in the future need to have full permitting and designs prior to outsourcing.

<u>Transmission Construction</u>

Attendees- Paul Chapman, Jerry Barstad, Cliff Coulter, Scott McConnachie, Robert Bonner, Mark Hertzberg and Brian Konrad

What Went Well?

The Construction of the project went well:

The crews had good contract service support. On a scale of 1-5 the average rating is a 4.

The crews maximized the use of internal and external resources to deliver upon the desired outcome.

They constructed the pipeline safely without an incident or accident.

The construction team had the Engineering specifications and documentation to execute the installation.

Using large water storage tanks was a good process and needs to be continued.

Transmission Construction Continued-

What we need to improve?

They stated that they need to improve on scheduling with the impacted landowners.

We need to have better communication from the Project Manager about the expectations of the project. They stated that they did not know all the details of the easements and how they should leave the private properties.

They need a daily JHA Job Hazard Assessment formal process so they can conduct daily tailgaters and identify the hazards associated with the task.

We need to build upon the success of the Enduro Eurocast dewatering pigs. The pipeline to be pigged requires preloaded head pressure so the pigs do not exceed 5-7 mph.

We need to install weld by flange pigging valve assemblies for testing and dewatering.

We need to install Pig Sigs on all pig launchers and receivers. (Post Construction caliper pig runs).

We need to create head pressure on the pipeline when dewatering so the pigs do not travel excessive speeds on lengthy project projects.

We need to calculate for elevation changes on the Hydro test documents.

We need to build flange adapters for the pig launchers and catchers. 150 ANSI - 300 ANSI; 300 ANSI - 600 ANSI

We need to create a work plan that identifies task that may require extended shifts. We also talked about what protocol should take place when an unplanned event requires extended shifts. For a start the crews need to communicate with leadership.

We talked about how to balance productivity while managing employee fatigue.

COMMENTS
The Corvallis Loop was a successful project. We have a supply system that benefits the Corvallis/ Philomath service area. The local delivery system will be improved even more when the Willamette Valley Feeder supplies the Corvallis Loop Pipeline. The sponsors of the project are satisfied with the results of the project.

SCORING	
Adequate Staffing	4
Adequate Budget	1- Original Budget 2- Revised Budget
Adequate Timeframe	1- Original Schedule 2- Revised Schedule
Management Support	4

We started the project before having permitting, land acquisition and design finalized.

The low scores on budget and timeframe scored low due to we did not hold budget or schedule.

The deliverables on the revised budget consumed 100% of the budget including all available contingency funding therefore this was scored as a 2. The project labor estimate did not allow for the extended time that was used to execute the 6454' intersect bore. The bore was complex due to changing geographical and physical features explained in the Challenges section above.

The revised execution schedule resulted in a low score of 2 due to the fact of having to utilize resources fully to tie the Willamette river bore sections within the floodplain. We experienced heavy rains that effected production rates.

Budget Variance Table

Corvallis Loop	No COH or AFUDC			With COH & AFUDC		
	Actual	Budget	Variance	Actual	Budget	Variance
Direct Costs	**$21,824,526**	**$13,939,370**	**$ 7,885,156**	**$28,021,994**	**$17,703,000**	**$10,318,994**
Change Order #1		$ 7,125,143	$ (7,125,143)		$ 9,048,931	$ (9,048,931)
Change Order #2		$ 872,062	$ (872,062)		$ 1,107,519	$ (1,107,519)
Subtotal	**$21,824,526**	**$21,936,575**	**$ (112,049)**	**$28,021,994**	**$27,859,450**	**$ 162,544**
Vehicle Overhead *	$ 352,757		$ 352,757	$ 352,757		$ 352,757
Total	**$22,177,283**	**$21,936,575**	**$ 240,708**	**$28,374,751**	**$27,859,450**	**$ 515,301**

* Vehicle Overhead as a percentage of direct labor was not included in the initial budgets or the subsequent change orders.

NW Natural

Budget to Actuals for 200363 - Corvallis Reinforcement
Project LTD as of August 2015

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• Amounts do not include COH or AFUDC unless otherwise specified
• YTD actuals include all months of the current year through the period selected

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WBS Element	A Approved Budget All Fiscal Years	B WBS Transfers	C Supplements / Returns (+/-)	D (A+B+C) Authorized Spend	E Actuals to Date All Fiscal Years	F (E-A) Variance from Approved Budget	G (E/A) % Utilized Approved Budget	H (E-D) Variance from Authorized Spend	I (E/D) % Utilized of Authorized Spend	J Actuals + Overheads
200363 Corvallis Reinforcement	**$21,936,575**	**$0**	**$0**	**$21,936,575**	**$22,177,282**	**$240,707**	**101%**	**$240,707**	**101%**	**$28,374,751**
200363-01 Design - Corvallis Reinforcement	$0	$0	$0	$0	$5,090,596	$5,090,596	Infinity	$5,090,596	Infinity	$6,174,799
200363-02 Construction	$0	$0	$0	$0	$16,952,829	$16,952,829	Infinity	$16,952,829	Infinity	$22,034,846
200363-02-01 12" (W)	$0	$0	$0	$0	$1,688,920	$1,688,920	Infinity	$1,688,920	Infinity	$2,143,365
200363-02-02 Phase 1 - Riverside Dr & Bridal (Waggle)	$0	$0	$0	$0	$1,018,216	$1,018,216	Infinity	$1,018,216	Infinity	$1,308,434
200363-02-02-01 12"W Waggle Bridle	$0	$0	$0	$0	$66,230	$66,230	Infinity	$66,230	Infinity	$86,808
200363-02-02-02 10"W Waggle Bridle	$0	$0	$0	$0	$385,988	$385,988	Infinity	$385,988	Infinity	$463,139
200363-02-02-03 Dist Reg 2-158-020-R-02	$0	$0	$0	$0	$19,418	$19,418	Infinity	$19,418	Infinity	$29,615
200363-02-02-04 8" (W) Waggle Bridle	$0	$0	$0	$0	$1,187	$1,187	Infinity	$1,187	Infinity	$1,503
200363-02-02-05 6" (W) Waggle Bridle	$0	$0	$0	$0	$16,768	$16,768	Infinity	$16,768	Infinity	$23,037
200363-02-02-06 4" (W) Waggle Bridle	$0	$0	$0	$0	$1,444	$1,444	Infinity	$1,444	Infinity	$1,709
200363-02-02-07 12"(W) Waggle Buildout	$0	$0	$0	$0	$204,104	$204,104	Infinity	$204,104	Infinity	$270,291
200363-02-02-08 10"(W) Waggle Buildout	$0	$0	$0	$0	$163,341	$163,341	Infinity	$163,341	Infinity	$218,538
200363-02-02-09 6"(W) Waggle Buildout	$0	$0	$0	$0	$115,068	$115,068	Infinity	$115,068	Infinity	$154,333
200363-02-02-10 3/4"(W) Waggle Buildout	$0	$0	$0	$0	$44,668	$44,668	Infinity	$44,668	Infinity	$59,461

NW Natural

Budget to Actuals for 200363 - Corvallis Reinforcement
Project LTD as of August 2015

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200363-02-03 Phase 2 - Riverside Drive to Hwy 34	$0	$0	$0	$0	$3,167,339	$3,167,339	Infinity	$3,167,339	Infinity	$4,349,357
200363-02-03-01 12"(W)Phase 2A - Riverside Trench #1	$0	$0	$0	$0	$838,442	$838,442	Infinity	$838,442	Infinity	$1,146,961
200363-02-03-02 Phase 2B	$0	$0	$0	$0	$288,914	$288,914	Infinity	$288,914	Infinity	$394,955
200363-02-03-02-01 12"(W)	$0	$0	$0	$0	$288,914	$288,914	Infinity	$288,914	Infinity	$394,955
200363-02-03-03 Phase 2C	$0	$0	$0	$0	$953,696	$953,696	Infinity	$953,696	Infinity	$1,313,934
200363-02-03-03-01 12"(W)	$0	$0	$0	$0	$929,531	$929,531	Infinity	$929,531	Infinity	$1,274,909
200363-02-03-03-02 Service pipe 2C	$0	$0	$0	$0	$4,218	$4,218	Infinity	$4,218	Infinity	$5,175
200363-02-03-03-03 Install service reg	$0	$0	$0	$0	$19,947	$19,947	Infinity	$19,947	Infinity	$33,849
200363-02-03-04 Phase 2D	$0	$0	$0	$0	$1,086,287	$1,086,287	Infinity	$1,086,287	Infinity	$1,493,508
200363-02-03-04-01 12" (W) X52 Bore #3	$0	$0	$0	$0	$1,053,033	$1,053,033	Infinity	$1,053,033	Infinity	$1,450,036
200363-02-03-04-02 2"(P)	$0	$0	$0	$0	$33,255	$33,255	Infinity	$33,255	Infinity	$43,472
200363-02-04 Phase 3 Hwy 34 Bridle (Glazier)	$0	$0	$0	$0	$613,993	$613,993	Infinity	$613,993	Infinity	$798,090
200363-02-04-01 16" (W)	$0	$0	$0	$0	$274,500	$274,500	Infinity	$274,500	Infinity	$340,749
200363-02-04-02 12" (W)	$0	$0	$0	$0	$330,793	$330,793	Infinity	$330,793	Infinity	$445,482
200363-02-04-03 6" (W)	$0	$0	$0	$0	$5,746	$5,746	Infinity	$5,746	Infinity	$7,989
200363-02-04-04 4" (W)	$0	$0	$0	$0	$1,552	$1,552	Infinity	$1,552	Infinity	$2,033
200363-02-04-05 2" (W)	$0	$0	$0	$0	$1,112	$1,112	Infinity	$1,112	Infinity	$1,457
200363-02-04-06	$0	$0	$0	$0	$290	$290	Infinity	$290	Infinity	$380

NW Natural

Budget to Actuals for 200363 - Corvallis Reinforcement
Project LTD as of August 2015

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3/4" (W)										
200363-02-05 Phase 4 Hwy 34	$0	$0	$0	$0	$4,883,635	$4,883,635	Infinity	$4,883,635	Infinity	$6,010,923
200363-02-05-01 Phase 4A	$0	$0	$0	$0	$1,098,439	$1,098,439	Infinity	$1,098,439	Infinity	$1,310,774
200363-02-05-02 Phase 4B	$0	$0	$0	$0	$464,299	$464,299	Infinity	$464,299	Infinity	$563,163
200363-02-05-03 Phase 4C	$0	$0	$0	$0	$374,411	$374,411	Infinity	$374,411	Infinity	$453,058
200363-02-05-04 Phase 4D	$0	$0	$0	$0	$1,083,769	$1,083,769	Infinity	$1,083,769	Infinity	$1,314,062
200363-02-05-05 Phase 4E	$0	$0	$0	$0	$271,182	$271,182	Infinity	$271,182	Infinity	$323,502
200363-02-05-06 Phase 4F	$0	$0	$0	$0	$926,776	$926,776	Infinity	$926,776	Infinity	$1,127,780
200363-02-05-07 Phase 4G	$0	$0	$0	$0	$450,769	$450,769	Infinity	$450,769	Infinity	$605,060
200363-02-05-08 DR 2-162-027-R2	$0	$0	$0	$0	$161,881	$161,881	Infinity	$161,881	Infinity	$247,807
200363-02-05-09 DR 2-162-027-R2 pipe	$0	$0	$0	$0	$2,715	$2,715	Infinity	$2,715	Infinity	$3,204
200363-02-05-10 DR 2-162-020-R1	$0	$0	$0	$0	$14,399	$14,399	Infinity	$14,399	Infinity	$21,791
200363-02-05-11 DR 2-162-020-R1 pipe	$0	$0	$0	$0	$34,994	$34,994	Infinity	$34,994	Infinity	$40,721
200363-02-06 Phase 5	$0	$0	$0	$0	$3,967,650	$3,967,650	Infinity	$3,967,650	Infinity	$5,435,498
200363-02-06-01 Phase 5A	$0	$0	$0	$0	$905,666	$905,666	Infinity	$905,666	Infinity	$1,223,803
200363-02-06-02 Phase 5B	$0	$0	$0	$0	$2,866,340	$2,866,340	Infinity	$2,866,340	Infinity	$3,955,114
200363-02-06-04 Phase 5D	$0	$0	$0	$0	$195,644	$195,644	Infinity	$195,644	Infinity	$256,581
200363-02-07 Phase 6	$0	$0	$0	$0	$1,499,024	$1,499,024	Infinity	$1,499,024	Infinity	$1,848,218

NW Natural

Project LTD as of August 2015

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200363-02-07-01 Phase 6A	$0	$0	$0	$0	$422,613	$422,613	Infinity	$422,613	Infinity	$510,781
200363-02-07-01-01 1030ft of 12" (W) Bore #9	$0	$0	$0	$0	$422,613	$422,613	Infinity	$422,613	Infinity	$510,781
200363-02-07-02 Phase 6B	$0	$0	$0	$0	$86,161	$86,161	Infinity	$86,161	Infinity	$111,241
200363-02-07-02-01 470ft of 12" (W) Trench #8	$0	$0	$0	$0	$86,161	$86,161	Infinity	$86,161	Infinity	$111,241
200363-02-07-03 Phase 6C	$0	$0	$0	$0	$782,628	$782,628	Infinity	$782,628	Infinity	$954,897
200363-02-07-03-01 Phase 6C 2263ft of 12" (W) X52	$0	$0	$0	$0	$715,646	$715,646	Infinity	$715,646	Infinity	$869,192
200363-02-07-03-02 Phase 6C 24ft of 6" (W) X42	$0	$0	$0	$0	$62,142	$62,142	Infinity	$62,142	Infinity	$79,825
200363-02-07-03-03 Phase 6C 27ft of 2" (W) B	$0	$0	$0	$0	$1,738	$1,738	Infinity	$1,738	Infinity	$2,104
200363-02-07-03-04 Phase 6C 10ft of 4" (W) X42	$0	$0	$0	$0	$3,102	$3,102	Infinity	$3,102	Infinity	$3,775
200363-02-07-04 Final project clean up order	$0	$0	$0	$0	$137,929	$137,929	Infinity	$137,929	Infinity	$178,837
200363-02-07-05 Dist. Reg 2-163-031-R-03	$0	$0	$0	$0	$14,604	$14,604	Infinity	$14,604	Infinity	$22,223
200363-02-07-06 DR 2-163-031-R3 pipe	$0	$0	$0	$0	$55,088	$55,088	Infinity	$55,088	Infinity	$70,240
200363-02-08 Cushman Road Rectifier	$0	$0	$0	$0	$59,783	$59,783	Infinity	$59,783	Infinity	$70,814
200363-02-09 OSU Finalize	$0	$0	$0	$0	$54,269	$54,269	Infinity	$54,269	Infinity	$70,147
200363-03 Land Acquisition	$0	$0	$0	$0	$119,483	$119,483	Infinity	$119,483	Infinity	$146,567
200363-04 Retirements	$0	$0	$0	$0	$14,374	$14,374	Infinity	$14,374	Infinity	$18,540

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL,	)
	)
Request for a General Rate Revision.	)

EXHIBIT 206 - SE EUGENE PROJECT

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

April 20, 2018

PROJECT NAME			SAP NO.	TIER
SE Eugene Reinforcement			201675	4
PROJECT MANAGER	**PROJECT SPONSOR**	**EXECUTIVE SPONSOR**	**DATE SUBMITTED**	
Andrea Kuehnel	Joe Karney	Grant Yoshihara	May 10, 2017	

PROJECT DESCRIPTION

Construct approximately 2-1/2 miles of 12" steel HP gas piping, a district regulator and distribution mains to connect and support the existing distribution system. The new HP pipeline would extend west from the existing South Eugene Gate and terminate at the connection to the existing 6" steel distribution main at Hilyard Avenue and near 30th Street. Distribution mains would be installed in conjunction with the HP to reinforce the existing distribution system to support existing and new customers. Several pipeline routes are being examined for feasibility. The preferred route selected considers existing infrastructure, available workspace, railroad crossings, and potential traffic impacts.

Gate station modifications may be necessary to serve the new pipeline, and may require that NWN takes over regulation from Williams pipeline. Evaluation of the gate station will be completed during the planning phase.

PROJECT PLATS	PROJECT LOCATION
Start 2-238-007 to End 2-237-011	Eugene Resource Center, City of Eugene, Lane County, OR

OBJECTIVES / BUSINESS CASE

The objective of the project is to reinforce the supply load center for Southeast Eugene, OR with approximately 3000 incremental Therms per hour on Peak Day. Providing adequate supplies to the southeast of Eugene, Oregon has been a growing concern for many years. Residential growth continues to expand south, away from existing high pressure supply pipelines, stressing the distribution system to failure. System modeling, verified through cold weather performance checks, project distribution system pressures of less than 5 psig and—for isolated areas under peak hour conditions—an inability to reliably serve existing firm service customers. This level of pressure is below the company's criterion of distribution system reinforcement being critical at pressures less than 10 psig. The Public Utility Commission of Oregon acknowledged NW Natural's 2016 IRP in Order No. 17-059, including the Action Item "Proceed with the SE Eugene Reinforcement project to be in service for the 2018/2019 heating season and at a preliminary estimated cost of $4 million to $6 million."

SCOPE

Construct approximately 2-1/2 miles of 8" or 12" steel HP gas piping, a district regulator and distribution mains to connect and support the existing distribution system. The new HP pipeline would extend west from the existing South Eugene Gate and terminate at the connection to the existing 6" steel distribution main at Hilyard and near 30th Street. Distribution mains would be installed in conjunction with the HP to reinforce the existing distribution system to support existing and new customers. Several pipeline routes are being examined for feasibility. The preferred route selected considers existing infrastructure, available workspace, railroad crossings, and potential traffic impacts.

OUT OF SCOPE

DELIVERABLES
Construct pipeline with capacity to deliver minimum 3,000 incremental Therms per hour to distribution system. District Regulator and associated distribution main to connect new HP main to existing DB system. Evaluate Gate Station for modifications to serve new main.

KEY TEAM MEMBERS			
Name	**Department**	**Role**	**% Utilized**
Andrea Kuehnel	Engineering	Engineer/PM	20%
Brian Konrad	Engineering	PM/Construction Manager	20%
Scott Lundgren	Engineering	Station Design	10%
Mike Smith	Engineering	FET	10%

SCHEDULE			
PLANNING/DESIGN: Proposed Dates			
Pln Start Date (quarter/year)	Q2 2017	**Pln End Date** (quarter/year)	Q1 2018
EXECUTION: Proposed Dates			
Exe Start Date (quarter/year)	Q2 2018	**Exe End Date** (quarter/year)	Q4 2018

MAJOR PHASES/MILESTONES		
Phase	**Estimated Start Date**	**Estimated End Date**
Planning	5/8/17	6/30/2018
Execution/Construction	7/1/2018	12/30/2018

PROJECT COSTS			
Actual Requested Planning Cost			
	Current Fiscal Year	**Future Fiscal Year(s)**	
Pre-Approved Design Work	$ 2,405	*N/A*---------------------------	**Actuals spent from $25k**
Additional Requested Planning Cost	$432,500	$204,500	**Capital** *(no COH/AFUDC)*
Estimated Execution Cost (+/-100%)			
	Current Fiscal Year	**Future Fiscal Year(s)**	
Est. Execution Cost	$0	$3M - $4.5M	**Capital** *(include contingency)*
Estimated Total Cost (+/-100%)			
	Current Fiscal Year	**Future Fiscal Year(s)**	
Total Estimated Cost w/ Contingency	$434,905	$3.2M - $4.7M	**Capital** *(includes contingency, no COH/AFUDC)*
Total Estimated Cost w/ COH & AFUDC	$517,500	$4M - $6M	**Capital** *(includes contingency & COH/AFUDC)*
PROECT COST INFORMATION			
Funding/Applicant	115/System Reinforcement		
COH Rate	19%		
Notes (Cost Constraints)	Gate station modifications not included in estimated execution total cost		
On-Going O&M Increases Projected			

Budget Assumptions	Design will avoid or limit impacts to Critical Habitat. Design will avoid or limit areas with potential Cultural Resources impacts. Joint Permit Application can be obtained for Amazon Creek crossing.

RISK / DEPENDENCIES / RELATED PROJECTS	
CONSTRAINTS	
ASSUMPTIONS	
RISK	See attached Risk Analysis
DEPENDENCIES	
RELATED PROJECTS	

CUSTOMER GROUP / STAKEHOLDERS		
NW Natural Stakeholders		**Comments**
X	Contract Services	
X	Corrosion	
	Distribution Crew	
X	Elect/Communications	Review Telecom needs
X	Environmental/Haz Mat	
X	Resource Management	
X	Gas Supply	
	Gasco/Mist/LNG Plants	
	Major Acct. Services	
X	Integrity Management	
X	Purchasing / Stores	
X	Resource Center Engineer	
X	Risk and Land	
X	Safety	
X	Specialty Const Crew (ROW)	
X	Station Design	
X	Surveying	
X	Transmission Const Crew	
X	Transmission Maint Crew	
X	Welders	
External Stakeholders		**Comments**
X	City	
X	County	
X	State	DSL/DEQ
X	Engineering Firm	
X	Property Owners	
	Other	

ATTACHMENTS:

Tier Assessment
Budget Summary
SAP Budget to Actuals LTD Report
Risk Analysis

PMO USE ONLY *ELECTRONIC APPROVALS*		
Title	**Name**	**Date/Time Approved**
Executive Sponsor(s)		
Project Sponsor(s)	Yoshihara, Grant; Karney, Joe;	5/8/2017 5:11PM
Project Manager	Kuehnel, Andrea F.	5/8/2017 4:20 PM
PMO Director	Wilson, Shante	5/11/2017 3:34PM
PRB Group		
Executive Committee	Anderson, David; sp_webservices; sp_webservices; Doolittle, Lea Anne; Yoshihara, Grant;	5/12/2017 8:41AM
CFO Approval		
Other Signator(s)		5/8/2017 5:11PM

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 344

	)
In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL,	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT 207 - DATA RESPONSES

TO THE

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

April 20, 2018

Rates & Regulatory Affairs
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Data Request Response

Request No.: UG 344 NWIGU DR 8

8. Reference "200 wp1 - Revenue Requirements Model", Tab "Exhibit 210 - Rate Base & Dep", row "22":

a. Please provide workpapers detailing the calculation of Accumulated Deferred Income Taxes – Other for the base year in the amount of $10,530,206. Please detail the accumulated deferred taxes, and the associated accumulated book-tax difference amounts, by book-tax difference.

b. Please provide workpapers detailing the calculation of Accumulated Deferred Income Taxes – Other for the test year in the amount of $15,598,282. Please detail the accumulated deferred taxes, and the associated accumulated book-tax difference amounts, by book-tax difference.

c. For each book-tax difference identified in sub-request (a) and (b) of this request, please provide the Company's best estimate of the period over which the book-tax difference is expected to reverse.

Response:

Please see the attached file, "CONFIDENTIAL **UG 344 NWIGU DR 8 Attachment 1.xlsx**."

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Request No.: UG 344 NWIGU DR 19

19. During the March 5, 2018, technical workshop, NW Natural mentioned that it uses a model to forecast capital spending that relies on historical statistical data. Please provide copies of this model along with a general description of how the model functions. Please provide the model in an Excel file with all formulas and links intact. If the Excel file links to another file, please provide a copy of the other file.

Response:

UI Planner is a financial and regulatory software application developed by Utilities International, a company headquartered in Chicago, IL. This software is specific to the utility industry, and Utilities International claims that their clients represent over 70% of the industry in terms of assets and revenue. The following link may provide further information regarding UI Planner: https://utilitiesinternational.com/about-us/

NW Natural finished the implementation of this application in 2015.

Given the nature of this software, models, calculations and reports are hosted in the application itself and not in Excel. Reports, however, can be exported to Excel. For example, responses to UG 344 OPUC DR 265 and GRC 18 OPUC SDR 4 include output reports out of the UI Planner application.

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Request No.: UG 344 NWIGU DR 22

22. In reference to NW Natural/800, Karney/3, lines 15-17, where Mr. Karney states "The SE Eugene Project is scheduled to begin construction in spring or early summer 2018, and is expected to be completed in fall of 2018."

a. Has NW Natural begun construction on the SE Eugene Project? If no, please state when construction is expected to begin.

b. Please provide NW Natural's best estimate of the expected in service date for the SE Eugene Project, based on all information known at this time.

c. Please provide the project charter and any associated change orders that have been submitted or approved with respect to the SE Eugene Project.

d. Please provide the latest capital estimates associated with the SE Eugene Project.

e. Please identify the monthly gross plant, depreciation reserve, accumulated deferred taxes and depreciation expenses associated with the SE Eugene Project included in the filed pro forma results of operations.

f. Did NW Natural prepare a cost/benefit analysis, or other similar economic analysis, when making the decision to construct the SE Eugene Project? If yes, please provide all such economic analyses, including any memoranda or documentation supporting the analyses.

Response:

a. Construction has not begun. Expected construction start date is June 2018.

b. Expected in service date for the SE Eugene project is September 30, 2018.

c. Please see UG 344 NWIGU DR 22 Attachment 1- 201675 SE Eugene Project Charter. There are no change orders associated with the project as of March 2018.

d. The current capital estimate is $4.8 million. The capital estimate will be updated upon receipt of contractor bids in April 2018. Cost estimate is expected to be on the upper end of the range estimated on the project charter.

e. Please see attached spreadsheet UG 344 NWIGU DR 22 Attachment 2. The total in-service amount in the attachment for this project is $6.1M. The difference between the $4.8M described above and $6.1M in the spreadsheet is due to COH/AFUDC.

f. See the attached UG 344 NWIGU DR 22 Attachment 3, the approved 201675 SE Eugene Alternatives Narrative FINAL.

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Request No.: UG 344 NWIGU DR 42

42. Reference NW Natural 1200, Page 2: NW Natural states "There are two elements of the revenue requirements model that are affected by tax reform. The first impact is the direct change in income tax expenses based on the reduction of the federal income tax rate from 35% to 21%. The second occurs in the accumulated deferred tax component of rate base, which reflects the loss of the higher "bonus" depreciation that had previously been available on a phase-out basis through the test year."

a. Is it NW Natural's proposal to exclude the impacts of Excess Tax Reserves (i.e. Excess Deferred Federal Income Taxes) as defined in § 13001(d) of the TCJA.

b. Does NW Natural agree that it will violate the IRS normalization requirements if, in computing its cost of service in this matter, NW Natural does not account for Excess Tax Reserves in the manner described § 13001(d) of the TCJA. Please explain.

c. Is it NW Natural's proposal to exclude the impact of deferring the revenue requirement benefits associated with the TCJA realized between January 1, 2018 and the rate effective date in this proceeding. Please explain.

d. Please provide all presentations and documents that the Company has received from its auditors or tax advisors discussing the implementation of the Tax Cuts and Jobs Act, since the Tax Cuts and Jobs Act was enacted into law.

e. Please provide NW Natural's best estimate of the impact of Excess Deferred Federal Income Taxes on test period revenue requirement. Please provide all workpapers, with all links and formulas intact, supporting the calculation. To the extent that the document includes hard-coded numbers, please identify and provide the source of the hardcoded number.

f. Does NW Natural track book accumulated depreciation by FERC account and by asset vintage? If yes, please prove accumulated depreciation by FERC account and by asset vintage as of 12/31/2017 (actual), 12/31/2018 (forecast) and 12/31/2019.

g. Does NW Natural track tax accumulated depreciation by FERC account and by asset vintage? If yes, please provide tax accumulated depreciation by FERC account and by asset vintage as of 12/31/2017 (actual), 12/31/2018 (forecast) and 12/31/2019.

Response:

NW Natural filed a TCJA related deferral application with the utility commission of Oregon on December 29, 2017. In addition, Staff at the Oregon Public Utility Commission filed a deferral application on December 29, 2017 with respect to the TCJA implications for NW Natural. As a result, regulatory accounting is being utilized to defer the net benefits associated the TCJA, including estimated excess deferred tax balances recorded at the end of 2017, and an estimate of the excess revenue occurring in 2018.

A TCJA tax workshop was held on February 28, 2017 that included representatives from all of the investor owned electric and gas utilities in Oregon, Staff from the Oregon Public Utility Commission, and representatives from Northwest Industrial Gas Users, Citizens Utility Board of Oregon, Sierra Club, Fred Meyer, Wal-Mart, and other interested parties. In follow up correspondence from Ms. Sommer Moser, from the Oregon Department of Justice (see email to all parties dated March 23, 2018), it was noted that supplemental filings regarding TCJA deferral applications are due later in April. It is NW Natural's intention to submit these supplemental filings.

a) It is not the intention of NW Natural to exclude the benefit of the excess deferred income taxes. The calculation of rate base, as included in the revenue requirement model referenced in NW Natural 1200, continues to include a reduction to rate base for the full amount of the revalued deferred income taxes (excess) recorded upon enactment of the TCJA. As a result, customers would continue to benefit from the excess deferred income taxes in the revenue requirement determination at the authorized rate of return.

   Until such time that customers receive the benefit of the excess deferred taxes in another manner (*Examples:* bill credit, offset to existing regulatory assets, allocation or offset to a capital project, etc. as discussed at the workshop) they would continue to benefit from the lower rate base balance.

   Each of the examples noted above provides a meaningful economic return to customers:

   Bill Credit – Bill credits would be a dollar for dollar refund of excess deferred income taxes. The reduction in the excess deferred income tax balance would also result in an increase to rate base and related revenue requirement.

   Existing Regulatory Asset Offset – Applying excess deferred income taxes as an offset to an outstanding regulatory asset, such as the pension balancing account, would result in a reduction to the customer recovery requirement of the regulatory asset balance and reduce the future interest charge on that balance. The reduction in the excess deferred income tax balance would also result in an increase to rate base and related revenue requirement.

   Capital Project Allocation - Applying excess deferred income taxes as an offset to new or existing capital projects would reduce the cost basis of the asset, its cost of recovery inclusion in depreciation, and its corresponding influence on rate base. The reduction in the excess deferred income tax balance would also result in an increase to rate base and related revenue requirement.

   It is anticipated that the amortization of excess deferred income taxes subject to normalization will result in annual amounts that vary, perhaps significantly, from year to year. As a result, inclusion in base rates per the revenue requirement of a particular annual amount, such as that may occur in a single test year, may result in a disconnect in later years when the amount that has been built into base rates per the revenue requirement differs significantly from the actual amortization amount in those later years. It may be more appropriate to address the annual amortization of these normalized amounts in a separate mechanism that can reflect the annual change in amortization in real time. This would help to ensure that in years that amounts are increasing that customer benefits are not delayed, and in years that amounts are decreasing that normalization violations do not occur.

b) Customers continue to benefit from the estimated excess deferred income tax balance as it is currently included as a reduction to rate base. As provided in §13001(d)(1), of the TCJA, a normalization violation occurs if excess tax reserves are reduced more rapidly, or to a greater extent than such reserve would be reduced under the average rate assumption method (ARAM). An accelerated reduction of the excess deferred income tax balance, beyond that which would be provided for under ARAM, was not included in the filing. Please see the discussion in a) above.

c) It is not the intention of NW Natural to exclude the benefit of the excess revenue deferral occurring in 2018. NW Natural is currently recording a deferral of estimated excess revenue in 2018, based on the forecasted benefit of the lower federal corporate income tax rate provided in the TCJA, for the period from January 1 through October 31, 2018. To determine the net reduction to income tax expense from the TCJA, NW Natural is utilizing a forecasted annual results of operations report to perform a with and without TCJA calculation. Beginning in January of 2018, the reduced tax amount, grossed up for income taxes, is recorded as a reduction to current revenue, with an equal offset to a new regulatory liability account. The actual deferral amount, for the full ten month period, will not be known until after October of 2018. In addition, the application of earnings test consideration usually applies to deferrals. Earnings test implications may not be known until the calendar year is complete.

   The determination of the deferral amount, using actual 2018 results, is consistent with the direction provided by Ms. Sommer Moser, from the Oregon Department of Justice (see email to all parties dated March 23, 2018), in follow up correspondence from the tax workshop held in late February. Deferrals of revenue, such as that one at issue here, are usually subject to amortization over the gas year (November to October) or in a single lump sum if significant. In the meantime, NW Natural is accruing interest, to the benefit of customers, until a determination can be made regarding the disposition of this deferral balance.

d) See files enclosed:

   UG 344 NWIGU DR 42 Attachment 1- Deloitte Accounting for Income Taxes Qtrly Hot Topics.pdf

UG 344 NWIGU DR 42 Attachment 2- Deloitte Frequently Asked Questions About Tax Reform.pdf

UG 344 NWIGU DR 42 Attachment 3- Deloitte Power and Utilities Quarterly Accounting Update.pdf

UG 344 NWIGU DR 42 Attachment 4- PwC Accounting considerations of US tax reform.pdf

UG 344 NWIGU DR 42 Attachment 5- PwC Sample Disclosure Tax Reform.pdf

UG 344 NWIGU DR 42 Attachment 6 – PwC SEC staff provides accounting and reporting.pdf

UG 344 NWIGU DR 42 Attachment 7- PwC Tax reform readiness.pdf

e) As noted in the discussion in a), above, it is anticipated that the amortization of excess deferred income taxes subject to normalization will result in annual amounts that vary, perhaps significantly, from year to year. As a result, inclusion in base rates per the revenue requirement of a particular annual amount, such as that may occur in a single test year, may result in a disconnect in later years when the amount that has been built into base rates per the revenue requirement differs significantly from the actual amortization amount in those later years. It may be more appropriate to address the annual amortization of these normalized amounts in a separate mechanism that can reflect the annual change in amortization in real time. This would help to ensure that in years that amounts are increasing that customer benefits are not delayed, and in years that amounts are decreasing that normalization violations do not occur.

As noted in part c) of “UG 344 NWIGU DR 38 NWN Response.docx,” the future annual amortization amounts of EDIT balances subject to normalization is not yet known. It will take additional time to prepare the amortization schedules under the normalization rules.

f) and g) The request for accumulated book and tax depreciation, in the context of this overall data request NWIGU DR 42, appears to be an effort to gather information to allow a third party to prepare their own ARAM amortization analysis. The information requested, on its own, would be insufficient to prepare an analysis of this nature. However, we are providing book and income tax projected accumulated depreciation for the years ending 2017, 2018 and 2019 attached as UG 344 NWIGU 42 Attachment 8. This information includes depreciation on assets placed in service through 2017 (does not include projected additions for 2018 or 2019). The accumulated depreciation figures are segregated by asset vintage (the year the assets were placed in service). The book accumulated depreciation figures include method / life depreciation but do not include other plant accruals, such as cost of removal, salvage value, gain /

loss on disposal, etc. The income tax accumulated depreciation figures are also method / life depreciation for the ease of comparison.

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Request No.: UG 344 NWIGU DR 43

43. Reference NW Natural 1200, Page 2: Please provide the Company's best estimate of the revenue requirement effect of incorporating the following adjustments into the final the final revenue requirement approved in Docket UG 221:

a. A reduction to the federal income tax rate from 35% to 21% used in the calculation of current and deferred federal income taxes.

b. A reduction to the federal income tax rate used in the conversion of net operating income to revenue requirement.

c. Application of excess deferred federal income taxes, as required under the new normalization requirements.

d. Any other changes to computation of current and deferred taxes in the referenced revenue requirement resulting from the passage of the TCJA that the Company believes is relevant.

Response:

NW Natural objects to this data request as unduly burdensome and improper to the extent it requires the Company to develop information or prepare a study for another party (OAR 860-001-0500(4)). Without waiving its objection, the Company does not have an estimate of the effects requested.

UG 344 NWIGU DR 44 Attachment 5

	Test Year	2016	2015	2014
Gas Technologies Istitute (GTI) - Utilization Technology Development	$335,000	$335,000	$335,000	$335,000
Gas Technologies Istitute (GTI) - Operations Technology Developmen	$240,000	$240,000	$240,000	$240,000
Oregon Seismic Prepardenedess Research	$50,000	$50,000	$50,000	$50,000
Gas Technology Institute - RNG Production from Woody Biomass	$0	$175,000	$0	$0
Total Energy Consortium Funding	$625,000	$800,000	$625,000	$625,000

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<u>Data Request Response</u>

<u>Request No.</u>: UG 344 NWIGU DR 44

44. Reference the NW Natural's response to NWIGU Data Request 11:
a. Please provide workpapers supporting the calculation of the $76,000 R&D tax credit amount.
b. Please detail the amount of energy consortium funding forecast in the test period, included detail for each energy consortium to which funding is assumed.
c. For each calendar year 2014, 2015, and 2016, please identify the amount of energy consortium funding for each energy consortium that received funding.

<u>Response:</u>

a. UG 344 NWIGU DR 44 Attachment 1 is the workpaper that supports the calculation of the $76,000 R&D Tax Credit in 2015. UG 344 NWIGU DR 44 Attachments 2-4 are the energy consortium invoices for the expenses used in Attachment 1.

b. UG 344 NWIGU DR 44 Attachment 5 details the amount of energy consortium funding forecast in the test period, including detail for each energy consortium to which funding is assumed. Also included in this file is the calendar years 2014, 2015 & 2016 as requested in (c).

c. See (b).

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Request No.: UG 344 NWIGU DR 45

45. Reference NW Natural's response to NWIGU Data Request 19:

a. Please explain with specificity how NW Natural forecasts post-test period capital additions which are not associated with discrete projects, and provide all workpapers used to develop such forecast.

b. In the March 5, 2018 technical workshop, NW Natural mentioned that it used a separate Excel model to forecast the post-test period capital additions which are not associated with discrete capital projects. Please provide a copy of that model.

c. Please provide detail of forecast capital expenditures (transfers to plant) by project and month over the period January 1, 2018 through December 31, 2019 considered in revenue requirement results. To the extent a capital expenditure cannot be attributed to any discrete project, please also identify the amount of such forecast capital expenditures by month over the same period.

d. For each forecast capital expenditure identified in sub-request (c) to this request, please explain how the capital forecast was developed.

e. Please provide historical capital expenditures (transfers to plant) by project and month over the period January 1, 2014 through December 31, 2017. To the extent a capital expenditure cannot be attributed to any discrete project, please also identify the amount of such forecast capital expenditures by month over the same period.

Response:

a. Note: the questions ask for "forecast post-test period". This would mean forecast after October 2019. We assume that the intention of the question was mean to be "forecast post-base period".

   The capital expenditure projections are built from the ground up with large projects and run-rate expenditures identified. This is accomplished using historical and projected spend patterns in combination with known project work that is required to effectively serve customers, improve our system and operations, or serve additional customers in our area.

   Large projects are captured under each "Applicant" (internal type of work/category) where the expenditure will occur, along with any run-rate component. Certain categories are built mostly from run-rate spend as the projects that happen throughout the year are smaller and/or often unidentified at the time of budget, yet continually come about each year.

Large projects are provided with an in-service date, and the run-rate amounts are closed to plant using a percent allocation. This allocation is based on an average length of time in which these smaller projects sit in CWIP prior to closing. This allocation is usually between 1-3 months depending on the type of work. UG 344 NWIGU DR 45 Attachment 1 includes the percent to close amounts by Applicant code, showing the rate at which non-specific project spend is placed into service in the model.

b. At the workshop, it was mentioned that UI Planner is the application used for planning and forecasting purposes. Inputs and assumptions reside in the UI Planner system. Information, however, can be exported to Excel. A UI Planner output report showing both discrete and non-discrete expenditures is included in UG 344 OPUC DR 203 Attachment 2.

c. Please see UG 344 NWIGU DR 45 Attachment 2. Blanket projects include non-discrete large project bookings.

d. Please see b.

e. Please see UG 344 NWIGU DR 45 Attachment 3, with closings to plant by year.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 344

In the Matter of	)
	)
NORTHWEST NATURAL GAS	)
COMPANY, dba NW NATURAL	)
	)
Request for a General Rate Revision.	)
	)

OPENING TESTIMONY OF EDWARD A. FINKLEA

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

April 20, 2018

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Edward A. Finklea. My business address is 545 Grandview Drive, Ashland, Oregon 97520. I am the Director of Natural Gas for the Alliance of Western Energy Consumers. My qualifications are provided in Exhibit AWEC/301.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC").[1/] AWEC members include diverse industrial and commercial interests that purchase sales and transportation services from Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company").

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. The only exhibit included with my testimony is my qualifications statement included as Exhibit AWEC/301.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony sets forth the reasoning behind AWEC's recommendation that certain rate schedules receive a 7.5% rate decrease even as other rate schedules receive increases. I will also address the policy implications of NW Natural's rate spread recommendation, which ignores the rate disparities shown in the Company's Long Run Incremental Cost ("LRIC") study and instead argues that any revenue increase in this case should be spread on an equal percentage of margin basis to all rate schedules.

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1 On March 31, 2018, Northwest Industrial Gas Users ("NWIGU")merged into the Industrial Customers of Northwest Utilities ("ICNU"), and on April 1, 2018 ICNU changed its name to Alliance of Western Energy Consumers ("AWEC"). The advocacy and work previously performed by NWIGU now occurs as part of AWEC.

Q. WHAT IS AWEC'S RATE SPREAD RECOMMENDATION?

A. Even though greater decreases are justified**,** AWEC's witness Mr. Gorman recommends applying a 7.5 percent margin rate decrease to all rate schedules that are shown by the Company's LRIC study to be paying more than their cost of service. The schedules that deserve a margin decrease are Industrial Sales Firm (Rates 031SF, 311SF, and 32ISF, Commercial Sales Firm (Rate 31 CSF and 32 CSF) Commercial Transportation Firm (31CTF), Industrial Transportation Firm (31ITF), Transportation Firm (32IS) Commercial Sales Interruptible (32CSI), Industrial Sales Interruptible (32IS) and Transportation Interruptible (32TI). Since the Company's LRIC study indicates that the current distribution rates paid by Residential Sales Firm (02) and Commercial Sales Firm (Rates 03CSF and 27CSF) under-collect their respective cost of service, those schedules receive slightly more of an increase than under the Company's proposal. I note, however, the size of the Residential Sales Firm (02) and Commercial Sales Firm (Rates 03CSF and 27CSF) increase is dramatically less than if more significant movement was made toward rate parity. It is my judgment that, even though a greater margin decrease is warranted, a 7.5% margin decrease for the schedules that are significantly overpaying is fair movement towards cost of service and avoids rate shock to other customer classes experiencing an increase. In light of the rate disparities that exist, other alternatives, such as equal percent of margin increases that provide no movement toward parity, are fundamentally unfair to the customers that overpay for service.

Q. IS YOUR RECOMMENDATION BELOW THE LEVEL MR. GORMAN SAYS IS A PRINCIPLED OUTCOME?

A. Yes, far below. Mr. Gorman shows that greater than 30% reductions in margin are in order for some rate schedules even if residential and commercial customers' rate increases are held to no more than 1.5 times the system average margin increase. Mr. Gorman's recommendation is grounded in solid cost of service principles and recognizes the principle of gradualism. As Director of Natural Gas for AWEC, and based on my involvement in natural gas rate cases for approximately 30 years, it is my judgment that a 7.5% decrease in margin is meaningful without being perceived as an extreme outcome. However, if the outcome of the case results in a minor overall rate increase, or even a decrease, I would urge the Commission to take that opportunity to make even more movement toward parity among rate classes.

Q. DO YOU DISAGREE WITH THE COMPANY'S RECOMMENDED RATE SPREAD?

A. Yes. Such an outcome would undermine Integrated Resource Planning ("IRP") and fundamental notions of fairness in the face of customer class rate disparities. If rate disparities are not addressed when a local distribution company faces a general rate increase, then those rate disparities will never be addressed. Such an outcome undermines the principles of fairness that are the underpinnings of rate-making for Oregon natural gas local distribution companies ("LDC").

Q. HAVE LDC CUSTOMER CLASS RATE DISPARITIES BEEN AN ISSUE IN PREVIOUS OREGON RATE CASES?

A. Yes, for many decades. The first LDC rate case I was involved in was UG 14, in the mid-1980s. Class cost allocation was one of the issues in that case. Since that time, there have been running disputes regarding the equitable allocation of LDC delivery costs. In most cases, cost studies show that industrial customers pay more than parity for delivery service, while residential and small commercial customers with low load factors pay below parity rates. In order to completely eliminate rate disparities, industrial customers would have to receive rate decreases when other customers are getting increases, so many times industrial customers have been asked to wait for the next rate case to make movement towards cost of service. The next rate case would then result in the same outcome, and so on.

Q. HAS THERE BEEN GENERAL CONSENSUS IN PAST RATE CASES AMONG THE PARTIES THAT THE LRIC STUDY HAS BEEN PREPARED PROPERLY?

A. Not always, but in this case AWEC is not disputing the Company's LRIC study. In several recent cases involving Avista and Cascade, as well as in the 2012 NW Natural case, there have been discussions about the proper construction of LRIC studies and parties have disputed various aspects of the studies. But the major issue from my perspective was whether the ultimate rate spread reflected the results of the LRIC study.

Q. HAVE THE RATE DISPARITIES EVER BEEN ADDRESSED IN A RESPONSIBLE MANNER IN YOUR OPINION?

A. On occasion there has been movement towards cost of service, predominately through settlements. There have been settlements where no increase is allocated to industrial customers. There have even been cases where decreases for some customer classes have been agreed to when other customer classes received increases.

Q. HAS THE COMMISSION EVER RULED ON SUCH MATTERS?

A. Yes. In the 2014 Avista rate case, the Commission ruled that no increase would be allocated to Avista's industrial customers while residential and small commercial customers received significant increases. NWIGU and Avista did argue for decreases for industrial customers based on the results of the LRIC study, but the Commission rejected that outcome in that particular proceeding. The rate disparities in that Avista matter were not as severe as the disparities that have been revealed by NW Natural's LRIC study.

Q. WHAT HAPPENED IN THE MOST RECENT NW NATURAL CASE?

A. NW Natural's 2012 rate case, Docket UG 221, is an example of where the parties negotiated a settlement that attempted to move rates closer to parity. There, the Company had initially proposed that certain customer classes receive a zero percent base margin increase. As part of the parties' stipulation, those customer classes received a five percent margin decrease instead. The Commission approved that decrease, along with the accompanying increase to other rate schedules.

Q. IF THERE WAS A DECREASE IN THE LAST CASE, WHY IS THERE STILL A RATE DISPARITY?

A. There are likely two factors. First, the last settlement made a modest movement towards cost of service and decreased the size of the rate disparity, but did not eliminate the disparities altogether. Second, the incremental cost of high volume high load factor service must be declining relative to the cost of residential and commercial service designed to meet winter peak demand.

Q. HOW DO THE RATE DISPARITIES SKEW THE IRP PROCESS?

A. The IRP process is a very serious and lengthy process whereby the stakeholders assess how to meet peak day demands in the future. Central to that analysis is that consumers are receiving price signals as to the cost of delivering natural gas on peak days. Because residential and small commercial customers are being charged rates below the incremental cost of providing service, many customers may be purchasing more peak service than they would be willing to pay if the service was priced at cost.

Q. HOW MUCH MOVEMENT TOWARD COST OF SERVICE ARE YOU RECOMMENDING RESIDENTIAL AND COMMERCIAL CUSTOMERS PAY TO ADDRESS THE RATE DISPARITIES?

A. By limiting the reduction for over-paying rate schedules to 7.5%, residential and small commercial customers would only pay 1.2 times the average margin increase. AWEC's recommendation recognizes the need for gradualism, without gradualism becoming an excuse to simply ignore rate disparities in perpetuity.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 344

In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT 301

TO THE

OPENING TESTIMONY OF EDWARD A. FINKLEA

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

April 20, 2018

Edward A. Finklea

545 Grandview Drive
Ashland, OR 97520

541-708-6338 ofc
503-413-0156 cell
E-mail: efinklea@awec.solutions

Primary Professional Experience

Lead counsel for the Northwest Industrial Gas Users ("NWIGU") from 1986 until 2008 in all regulatory interventions concerning Williams Gas Pipeline West and TransCanada Gas Transmission Northwest, and before state regulatory commissions concerning regulation of the five regional natural gas local distribution companies ("LDCs").

Represented NWIGU before the Federal Energy Regulatory Commission in interstate pipeline rate and certificate proceedings, before the Oregon Public Utility Commission in natural gas rate and other regulatory proceedings, before the Washington Utilities and Transportation Commission in natural gas rate, safety and other regulatory proceedings and in proceedings before the Idaho Public Utility Commission.

Employment History

Director of Natural Gas for Alliance of Western Energy Consumers ("AWEC") – April 1, 2018 to present

Executive Director for the Northwest Industrial Gas Users – August 2012 to March 31, 2018

Adjunct Professor at Northwestern School of Law, Lewis and Clark College "Law and Economics" – Current

Senior Counsel, NiSource Corporate Services Inc. Regulatory counsel to interstate pipeline, representing company before Federal Energy Regulatory Commission and advising company on federal regulatory compliance and business transactions – November 2009 to November 2011

Executive Director, Energy Action Northwest. Organization advocated for siting and permitting of interstate pipelines, liquefied natural gas terminals, and high voltage transmission projects in Oregon and Washington. Represented organization before state legislature and in media relations – July 2008 to October 2009

Partner, Cable Huston Benedict Haagensen & Lloyd. Private law practice specializing in energy law – 2004 to July 2008

Managing Partner, Energy Advocates LLP. Founded firm with offices in Portland, Oregon and Washington D.C. – 1997 to 2003

Partner, Ball Janik LLP – 1994 to 1997

Partner, Heller Ehrman White & McAuliffe – 1990 to 1994

Partner, Tonkin Torp Galen Marmaduke & Booth – 1986 to 1990

Associate, Garvey Schubert – 1986 to 1988

Assistant General Counsel to Northwest Natural Gas handling state regulatory matters and providing counsel to the company on energy projects, including a landfill gas project – 1984 to 1986

Counsel to the Bonneville Power Administration litigating electric rate issues in administrative hearings and defending BPA before the Ninth Circuit Court of Appeals – 1982 to 1984

Trial Attorney for the Federal Energy Regulatory Commission in hydroelectric licensing and co-generation regulation – 1981 to 1982

Law Clerk for the Council on Wage and Price Stability, Executive Office of the President of the United States – 1980 to 1981

Summary of Professional Engagements

Represented Columbia Gulf Transmission in general rate proceeding before the Federal Energy Regulatory Commission.

Represented applicants in proceeding before Federal Energy Regulatory Commission seeking authorization to provide incentive fuel mechanism and natural gas hub services.

Represented industrial gas consumers in contract negotiations for the purchase of natural gas commodity and interstate pipeline services.

Counsel to a medical center interconnecting a cogeneration plant with an investor-owned utility and advising client on long-term gas purchasing arrangement for electric generation.

Represented numerous clients to secure direct connections to interstate pipelines, addressing all regulatory issues involving certification of connecting facilities and operations of private pipelines.

Represented liquefied natural gas developer in governmental relations associated with securing federal and local permits for development of an energy project.

Represented customers in negotiating special contracts for purchasing natural gas distribution services from local utilities.

Represented public port authority in a pipeline siting issue.

Represented Eugene Water and Electric Board in select issues concerning Bonneville Power Administration.

Represented irrigation farmers in electric rate dispute involving FERC-licensed hydroelectric project before the Oregon Public Utility Commission.

Represented clients in trial court and appellate litigation on energy–related issues.

Represented industrial customer in anti-trust litigation and FERC refund proceedings stemming for 2000-2001 Western Energy Crisis.

Represented industrial electric customers in the restructuring of electric utilities in Oregon.

Represented an oil company shipper on an intrastate oil pipeline in rate proceeding before the Washington Utilities and Transportation Commission.

Individual clients while in private practice in addition to NWIGU included Alcoa, Armstrong World Industries, Blue Heron Paper, Boeing, ESCO, James River Paper (now Georgia Pacific) JR Simplot, Legacy Health Systems, MicroChip Technology, NorthernStar Natural Gas, Texaco Gas Marketing, Valley Medical Center, WaferTech, Wah Chang, West Linn Paper, and Weyerhaeuser.

Education	BA in Political Science from the University of Minnesota – 1974 J.D. Northwestern School of Law, Lewis and Clark College – 1980
Professional Memberships	Admitted to practice law in the States of Oregon and Texas and before several Federal district and appellate courts. Adjunct Professor at Northwestern School of Law, Lewis and Clark College "Northwest Energy Law" – 1984 to 2005 Past Chairman of "Energy, Telecom and Utilities" section of the Oregon State Bar. Member of the Federal Energy Bar Association. Lecturer: Buying and Selling Electric Power in the West, Law Seminars International Conference. Presentations on natural gas industry – 2004 to 2009