Avista Corporation
East 1411 Mission Ave
Spokane, WA 99220

Evaluation of Avista's Washington Electric and Natural Gas Decoupling Mechanisms
Statement of Work

1. Project Overview

Avista Corporation ("Avista") is seeking a qualified firm ("Consultant") to complete an objective, independent evaluation of Avista's electric and natural gas decoupling mechanisms ("Decoupling Mechanisms" or "Mechanisms") approved by the Washington Utilities and Transportation Commission ("WUTC" or "Commission").

The Consultant will be required to complete the evaluation of the Mechanisms (the "Evaluation" or "Services") at the direction of Avista, in consultation with Avista's Energy Efficiency Advisory Group ("Advisory Group"). The Evaluation must be conducted in accordance with this Statement of Work ("SOW") including, without limitation, the "Objectives" described in Section 3 and the "Scope of Services described in Section 4. The Deliverables and Schedule associated with the Services are described below in Section 5.

2. Background

On November 25, 2014, in Dockets UE-140188 and UG-140189, the Commission issued a final order ("Order 05") approving Avista's electric and natural gas rate Decoupling Mechanisms. On March 25, 2020, the Commission issued a final order ("Order 09") granting continuation of Avista's electric and natural gas Decoupling Mechanisms approved under WUTC Order 05, subject to certain conditions set forth in Dockets UE-190334 and UG-190335 (the "Dockets"). The details of the Mechanisms and associated terms and conditions are described in the attached Settlement Stipulation in Order 05 (with references to Avista-filed testimony and that Order) and in Order 09.

To assist in understanding the criteria for the Services required under this SOW, the following attachments are being included for reference:

- ***Attachment A***, *Commission Order 05 with attached Settlement Stipulation.*
- ***Attachment B,*** *Commission Order 09 in the Dockets.* (See the Decoupling discussion beginning on page 29, paragraph 83 and ending on page 40, paragraph 115).
- ***Attachment C***, *Avista's Decoupling Evaluation Final Report.* (H. Gil Peach & Associates LLC, 10/01/2018).
- ***Attachment D***, *Avista's 2021 Electric Tariff Filing.*
- ***Attachment E***, *Avista's 2021 Natural Gas Tariff Filing.*

2.1 Description of Decoupling Mechanisms

Decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy (kilowatt hour and therm) usage ("Sales"). Avista's Decoupling Mechanisms were approved for a five (5) year period, effective January 1, 2015 (Order 05); the Mechanisms were approved for an additional five (5) year period under Order 09. Avista's actual Sales revenues vary (up and/or down) from the level reflected in general rate cases due to several factors including, without limitation, changes in weather, energy conservation and/or the economy. Under the Mechanisms, Avista's electric and natural gas revenues are adjusted each month, based on the number of customers rather than Sales, and the difference between revenues based on the number of customers and revenues based on Sales is deferred during the current 12-month period, and either "*surcharged*" (recovered) or "*rebated*" (refunded) to customers in the subsequent 12-month period through Avista's Tariffs.

Electric and natural gas Decoupling surcharge rate adjustments are limited to three percent (3%) on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period; there is no upper limit on rebate rate adjustments (for further information related to the Mechanisms, refer to Attachments D and E).

While the requirements for the Evaluation are described in Order 09, the following general requirements/references are intended to facilitate the Evaluation applicable under this SOW:

- Order 05 (¶113) required a third-party evaluation to be conducted three (3) years after Avista implemented the Decoupling Mechanisms, the results of which are set forth in Attachment C.
- Under Order 09, no party to the Dockets requested another third-party evaluation of the Mechanisms. However, the Commission ordered Avista to conduct another evaluation of the Mechanisms to assess the effect of the modifications required under Order 09.
- Order 09 requires a third-party evaluation of the Mechanisms that includes an analysis of the following elements:
  - The Mechanisms' impact on conservation,
  - The Mechanisms' impact on Avista's revenues, and
  - The extent to which fixed costs are recovered in fixed charges from the individual customer classes.
- In addition, the Evaluation must include an analysis of the effects of:
  - Excluding new customers from the Decoupling Mechanisms,
  - Using a moving average of weather data gathered by Avista regarding a 30-, 20-, 15-, and 10-year moving average, and
  - The three percent (3%) cap on annual surcharge rate adjustments compared with: (i) a five percent (5%) cap which has been approved for other utilities in Washington, and (ii) no cap on annual surcharge rate adjustments.

2.2 Description of the Energy Efficiency Advisory Group

The Advisory Group provides advise and non-binding oversight to Avista for achieving energy efficiency. The Advisory Group is currently comprised of staff from the Washington, Idaho, and Oregon public utility commissions, the Public Counsel Unit of the Washington Office of Attorney General, Northwest Energy Coalition, Spokane Neighborhood Action Partners, The Energy Project, Northwest Energy Efficiency Alliance, Northwest Power and Conservation Council, Northwest Energy Efficiency Council, Idaho Conservation League, Putnam Price, and the Opportunity Council.

3. Objectives

The Evaluation must include the following elements, to the extent data is available:

1. An audit of whether the deferrals and rates were calculated in accordance with the Commission order approving the Mechanisms (Order 09).
2. Analysis of the Mechanism's impact on Avista's revenues (i.e., whether there has there been a stabilizing effect).
3. Analysis of the extent to which fixed costs are recovered in fixed charges for the customer classes, excluded from the Mechanisms.
4. An analysis of each Mechanism's impact on conservation achievement, in total and by sector (residential, low-income, non-residential), and identification of conclusive or meaningful trends in the performance of Avista's electric and natural gas conservation programs since the inception of the Mechanisms (i.e., did Avista achieve a higher level of savings with the mechanisms in effect). This analysis should be based on information already available as part of Avista's biennial conservation achievement evaluations filed with the Commission including changes to program delivery strategies as reported in annual evaluations, significant changes in program budgets, or reported savings levels.
5. Analysis of the effects of excluding new customers from the decoupling mechanism.
6. Analysis of using a moving average of weather data shorter than 30 years based on the data gathered by Avista regarding a 30-, 20-, 15-, and 10-year moving average.

7. Analysis of the 3 percent cap on annual adjustments compared with (1) a 5 percent cap, had it been implemented as has been approved for other utilities in Washington, and (2) no cap on annual adjustments.
8. Identification of any conclusive evidence to suggest that the Mechanisms adversely impacted customer service, distorted price signals for customers resulting in lower participation in conservation programs, or eroded Avista's incentive to control costs and improve operational efficiency and/or Washington-required service quality measures.

4. Scope of Services

Consultant shall provide the labor and materials required to provide the Services applicable under this SOW including answering the following questions in order to meet the Objectives outlined in Section 3 above:

1. Were the Mechanisms administered and calculated correctly.
2. Were there any differences in Decoupling tracker adjustments between rate classes?
3. Were there any differences in conservation program savings, expenditures, and customers served between low-income customers and the rest of the residential class related to Decoupling?
4. Were there any trends in the performance of Avista's conservation programs since the inception of the Mechanisms, both in total and by sector (i.e., low-income, residential, and non-residential)?
5. Have the Mechanisms had an impact on natural gas conservation savings?
6. Have the Mechanisms had an impact on electric conservation savings (excluding the decoupling commitment to energy savings of 5%)?
7. What impact did the Mechanisms have on Avista's revenues (i.e., whether there has been a stabilizing effect)?
8. How much of Avista's fixed costs recovered from non-decoupling customer classes are recovered in fixed charges?
9. What were the causes of the deviation of actual revenue-per-customer from authorized revenue-per-customer?
10. Provide analysis and trends on whether the rate cap was reached and the results of the earnings test.
11. Provide an analysis of excluding new customers from the decoupling mechanisms.
12. What factors impacted the deferral and rate changes, and what was the magnitude of that impact? (e.g., weather, customer counts, conservation, economy, etc.)?
13. Provide analysis of the impact of using a moving average of weather data shorter than 30 years based on the data gathered by Avista regarding a 30-, 20-, 15-, and 10-year moving average.
14. What was the impact of the Decoupling deferral on Avista's revenues and rates?
15. What was the effect of updates to the decoupling baseline and resulting effects on deferrals under the Mechanisms?
16. Provide an analysis of the 3 percent cap on annual adjustments compared with (1) a 5 percent cap, had it been implemented as approved for other utilities in Washington, and (2) no cap on annual adjustments.

Consultant may also explore other trends and adverse impacts to improve the Evaluation. In conducting the Evaluation, Consultant shall rely, primarily, on existing data provided by Avista. All data must be: (i) necessary and justifiable to the Evaluation, and (ii) able to be provided within the time frame set forth in this SOW and budget approved by Avista.

Because work related to the identification of any trends in conservation performance and conclusive adverse impacts will require careful prioritization, Consultant shall use its previous experience and expertise to suggest areas of focus.

Consultant shall develop a good understanding of the details of the Decoupling accounting deferrals and rate calculations, as well as Avista's energy conservation programs by spending consulting with Avista employees as required, to work directly with Avista personnel who have subject matter expertise.

Avista will providing all data required by the Consultant, in a timely manner, to enable Consultant to complete the Evaluation, consistent with the project schedule ("Schedule") described below.

It is not an expectation that the work product contained in Avista's Decoupling Evaluation Final Report from 2018 included as Attachment C needs to be reevaluated.

Consultant shall characterize any conclusions or recommendations made as a result of Consultant's Evaluation, as Consultant's own and not representative or binding on the Commission, Commission Staff, Avista, or any member of the Energy Efficiency Advisory Group.

5. Schedule:

Consultant shall:

- Initiate the Evaluation the week of ***April 10, 2023***, or as otherwise requested by Avista.
- Provide the initial draft of the 3-year Evaluation Report (the "Report") to Avista for review, no later than ***August 11, 2023***.
- Incorporate Avista's comments, as applicable, and provide the second draft of the Report to Avista within five (5) business days of receipt of Avista's comments, or ***September 15, 2023***, whichever occurs last.
- Incorporate Avista's comments on the second draft, as applicable, and provide the final Report to Avista within five (5) business days of receipt of Avista's comments, or ***October 6, 2023***, whichever occurs last.

6. Deliverables

The format of the Report should be similar to Attachment C and include, at a minimum, the following elements:

- Executive summary
- Introduction and Project Overview
- Methods of Evaluation and Scope
- Measurement and analysis results
    - Audit of deferrals and rate calculations
    - Impacts of decoupling tariff tracker adjustments
- Assessment of any trends and adverse impacts
- Summary of Commission questions set forth above in Section 2.1
- Conclusions and recommendations
- Appendices

Consultant shall meet with Avista (either in-person at Avista's headquarters, or via conference call – as agreed to by the Parties) throughout the Evaluation process, including, at a minimum, (i) an initial meeting prior to April 10, 2023, to discuss a work plan, and (ii) periodically thereafter to present the results of the first draft Report and the second draft Report prior to providing the final Report to Avista in October 2023.

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	DOCKETS UE-140188 and UG-140189 (*Consolidated)*
Complainant,	)	ORDER 05
v.	)	FINAL ORDER REJECTING TARIFF FILING, ACCEPTING WITH CONDITIONS FULL SETTLEMENT STIPULATION, AUTHORIZING TARIFF FILING, AND REQUIRING COMPLIANCE FILING
AVISTA CORPORATION d/b/a AVISTA UTILITIES,	)	
Respondent.	)	
. . . .	)	

Synopsis: *The Commission rejects the tariff sheets Avista Corporation d/b/a Avista Utilities (Avista or Company) filed on February 4, 2014, by which the Company requested to increase electric base rates by $18.2 million, or 3.8 percent, and natural gas base rates by $12.2 million, or 8.1 percent. Instead, the Commission approves, with conditions a settlement filed by Avista, Commission Staff, Public Counsel, ICNU, NWIGU, and The Energy Project on August 18, 2014, and as amended on September 8, 2014.*

We approve the agreed upon increase in electric revenues by approximately $4 million or 0.8 percent, which includes the impact of a $3 million credit from the existing Energy Recovery Mechanism (ERM) deferral balance. In addition, the Commission approves an electric low income rate assistance program (LIRAP) funding increase of $0.4 million. To partially offset the rate impact of the expiration of the current period's ERM credit and Bonneville Power Administration transmission credits totaling approximately $13.7 million, the Commission approves a settlement that would rebate approximately $8.6 million of Renewable Energy Credit revenues to electric customers over 18 months. In addition, the Commission approves an increase in natural gas revenues by approximately $8.9 million or 5.58 percent, including a natural gas LIRAP funding increase of $0.42 million or 0.14 percent.

The Commission also approves the settling parties' request to implement electric and gas decoupling mechanisms for five years, as well as the use of a third-party evaluation, paid for by Avista shareholders and to be completed following the end of the third full year of the implementation of the mechanisms. We require the Company to consult with its Conservation Advisory Group in the development of the request for proposals (RFP) and the selection of the consultant to perform the evaluation. After incorporating input from its advisory group, Avista must file its draft RFP, including the scope of the evaluation query, with the Commission for its approval. At a minimum, we expect the evaluation to address decoupling's effect on revenues, its impact on conservation, the extent to which the allowed revenues are recovering their allocated cost of service by customer class, and the extent to which fixed costs are recovered in fixed charges for the customer classes excluded from the decoupling mechanisms.

The Commission orders that the LIRAP funding increase proposed in the Settlement be doubled, for a total electric LIRAP funding increase of $400,000 and a total natural gas LIRAP funding increase of $428,000 and encourages parties to file mutually agreed upon additions to the LIRAP program at the same time as any mutually agreed-upon modifications without waiting until the following year as contemplated by the Settlement. If the parties cannot agree upon modifications or additions to the program by June 1, 2015, they should file alternative or competing proposals with the Commission at that time

The Settlement proposed a separate forum in which the parties could discuss attrition and other rate making policy issues. We direct Staff to open an investigatory docket to discuss attrition and other rate making policy issues.

With the above additional requirements and conditions, we approve the Settlement Stipulation.

SUMMARY

1 **PROCEEDINGS:** On February 4, 2014, Avista Corporation d/b/a Avista Utilities (Avista or the Company) filed with the Washington Utilities and Transportation Commission (Commission) revisions to its currently effective Tariff WN U-28, Electric Service in Docket UE-140188, and its currently effective Tariff WN U-29, Gas Service in Docket UG-140189. In its filings, Avista requested authority to increase charges and rates for electric service by approximately $18.2 million or 3.8 percent. The overall electric increase Avista proposed is 5.5 percent, including the above-mentioned 3.8 percent base rate increase, a Renewable Energy Credit Revenue Mechanism rebate of 1.1 percent, and the expiration of two rebates currently received by electric customers totaling 2.8 percent, effective January 1, 2015.

2 The Company also requested a natural gas rate increase of $12.1 million, or 8.1 percent. On February 14, 2014, the Commission suspended operation of the tariffs and consolidated the dockets for hearing.

3 **PARTY REPRESENTATIVES:** David J. Meyer, Vice President and Chief Counsel for Regulatory and Governmental Affairs, Spokane, Washington, represents Avista. Brett P. Shearer, Assistant Attorney General, Olympia, Washington, represents the Commission's regulatory staff (Staff or Commission Staff).[1] Lisa W. Gafken, Assistant Attorney General, Seattle, Washington, represents the Public Counsel Section of the Washington State Attorney General's Office (Public Counsel).

4 Melinda J. Davison and Joshua D. Weber, Davison Van Cleve, P.C., Portland, Oregon, represent the Industrial Customers of Northwest Utilities (ICNU). Ronald L. Roseman, Attorney, Seattle, Washington, represents The Energy Project. Chad M. Stokes and Tommy A. Brooks, Cable Huston, Portland, Oregon, represent the Northwest Industrial Gas Users (NWIGU).

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[1] In formal proceedings, such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of the proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

5 **COMMISSION DETERMINATIONS:** The Commission approves and adopts the proposed Settlement Stipulation (Settlement) with the following conditions:

Decoupling Mechanisms and Third-Party Evaluator

- Avista must consult with its Conservation Advisory Group when developing the request for proposal (RFP) for the third-party evaluator tasked with reviewing the Company's five-year electric and natural gas decoupling mechanisms as well as the selection of the evaluator.
- After incorporating input from its advisory group, Avista must file its RFP with the Commission, including the scope of the evaluation query, for approval.
- At a minimum, the third-party evaluation must address decoupling's effect on revenues, its impact on conservation, the extent to which the allowed revenues are recovering their allocated cost of service by customer class, and the extent to which fixed costs are recovered in fixed charges for the customer classes excluded from the decoupling mechanisms.

LIRAP

- Avista must double funding for the low income rate assistance program (LIRAP) from the amount proposed in the Settlement.
- Using Staff's proposed pilot program as a basis, the parties should work together to file mutually agreed upon additions and modifications to the LIRAP. If the parties cannot agree upon modifications or additions to the program they should file alternative or competing proposals with the Commission no later than June 1, 2015.

Attrition

- Staff will open an investigatory docket to facilitate discussion of attrition and other rate making policy issues.

MEMORANDUM

I. Background and Procedural History

6 On February 4, 2014, Avista filed revisions to its currently effective Tariff WN U-28, Electric Service, and Tariff WN U-29, Gas Service. The Company requested authority to increase charges and rates for electric service by approximately $18.2 million, or 3.8 percent. The Company also requested a natural gas rate increase of $12.1 million, or 8.1 percent. On February 14, 2014, the Commission suspended operation of the tariffs and consolidated the dockets for hearing.

7 Avista based its initial request on a test year from July 1, 2012, through June 30, 2013. The filing included proposals for the following:

- An overall rate of return (ROR) of 7.71 percent.[2]
- A return on common equity (ROE) of 10.1 percent.[3]
- A capital structure consisting of 49.0 percent equity and 51.0 percent debt.[4]

8 On March 7, 2014, the Commission conducted a prehearing conference before Administrative Law Judge Marguerite E. Friedlander. On July 22, 2014, Staff, Public Counsel, The Energy Project, NWIGU, and ICNU filed response testimony and exhibits. Following notification from the parties that they had reached a full settlement, the Commission suspended the remaining procedural schedule on August 14, 2014. The Commission held public comment hearings in both Spokane and Spokane Valley, Washington, on August 26, 2014, and August 27, 2014, respectively. Collectively, 15 members of the public spoke at the public comment hearings. In total, the Commission and Public Counsel received 179 comments regarding the proposed rate increase from Washington customers, with 158 comments opposing

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[2] Morris, Exh. No. SLM-1T, at 3:18.

[3] *Id.*

[4] *Id.*

the increase, one comment supporting the increase, and 20 comments neither supporting nor opposing.[5]

9 On August 18, 2014, Avista, Staff, Public Counsel, ICNU, NWIGU, and The Energy Project filed a Settlement, attached to this Order as Appendix A. The settling parties also filed joint testimony in support of the Settlement on August 29, 2014. On September 8, 2014, the settling parties filed certain amendments to the Settlement and Joint Testimony to reflect corrections to the level of LIRAP funding increases. On September 23, 2014, the Commission convened a settlement hearing in Olympia, Washington. Chairman David W. Danner, Commissioner Philip B. Jones, and Commissioner Jeffrey D. Goltz were assisted at the bench by Judge Friedlander. Altogether, the record includes more than 200 exhibits entered during the settlement hearing. The transcript of this proceeding exceeds 250 pages in length.

10 On November 12, 2014, Avista filed, in compliance with conditions in the Settlement, an updated power supply revenue requirement increase of $5.6 million, an amount lower than the $6.3 million originally requested.

II. Settlement Stipulation

A. Introduction

11 The Commission's statutory duty, in the context of a general rate case, is to balance the needs of the public to have safe and reliable gas and electric service at reasonable rates with the financial ability of the utility to provide such service prospectively. In fulfilling its statutory duty, the Commission must establish rates that are "fair, just, reasonable and sufficient."[6] The rates must be fair to both customers and the utility; just, in that the rates are based solely on the record in this case following the principles of due process of law; reasonable, in light of the range of potential outcomes presented in the record; and sufficient, to meet the financial needs of the utility to cover its expenses and attract capital on reasonable terms.[7]

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[5] Exh. No. 5.

[6] RCW 80.28.010(1); RCW 80.28.020.

[7] *Federal Power Commission v. Hope Natural Gas,* 320 U.S. 591 (1944); *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia,* 262 U.S. 679 (1923). *See People's Organization for Washington Energy Resources v. Washington Utilities & Transportation Comm'n,* 104 Wn.2d 798, 807-13, 711 P.2d 319 (1985) (describing rate setting process in Washington).

12 Pursuant to WAC 480-07-750(1), the Commission will approve settlements when doing so is lawful, the settlement terms are supported by an appropriate record, and when the result is consistent with the public interest in light of all the information available to the Commission. Ultimately, in settlements, as in litigated rate cases, the Commission must determine that the resulting rates are fair, just, reasonable, and sufficient, as required by state law.

13 Thus, the Commission considers the individual components of the settlement under a three-part inquiry. We ask:

- Whether any aspect of the proposal is contrary to law.
- Whether any aspect of the proposal offends public policy.
- Whether the evidence supports the proposed elements of the settlement as a reasonable resolution of the issues at hand.

14 The Commission must reach one of three possible results:

- Approve the proposed settlement without condition.
- Approve the proposed settlement subject to one or more conditions.
- Reject the proposed settlement.

B. Terms and Conditions

1. Summary

15 On August 18, 2014, the Company filed a Settlement on behalf of all parties. The agreement itself is a "black box" Settlement. This means that the settling parties agree on some important components in the rate case, such as revenue requirement, decoupling mechanisms with a third-party evaluator, and rate spread and rate design, but the Settlement does not articulate the "give and take" process that produced these results. Put another way, the settling parties agree to firm end-result numbers without indicating which parties' adjustments or issues have been included in the final numbers.

16 Some of the contested issues that the Settlement proposes to resolve are:

- Rate increases for 2015 (both electric and natural gas);
- Five-year electric and natural gas decoupling mechanisms and third-party evaluations;
- Determination of power supply costs;
- Rate spread and rate design (both electric and natural gas); and
- Increased LIRAP funding.

The settling parties propose a January 1, 2015, effective date for the rate increases.[8] They indicate that this provision is an integral part of the Settlement.[9]

2. Discussion

a. Rate Increases

17 Effective January 1, 2015, the Settlement provides for an increase in Avista's annual electric revenues of $7.0 million, or 1.4 percent.[10] The overall net billed impact of this Settlement is an increase of $11.9 million, or 2.48 percent, consisting of an increase in base rates and the following revenue increases and credits due to:

- The January 1, 2015, expiration of the current Energy Recovery Mechanism (ERM)[11] and Bonneville Power Authority transmission[12] credits, increasing electric rates by $13.7 million or 2.8 percent.
- Mitigation of the increase in electric rates by using $3 million from the ERM deferral account, resulting in increased electric rates of only 0.8 percent.[13]

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[8] Exh. No. 5, ¶ 22.

[9] *Id.*

[10] Settlement, ¶ 4.

[11] Credit of approximately $9.2 million originated in Docket UE-120436 as an ERM refund.

[12] Credit of approximately $4.4 million stems from a settlement with the Bonneville Power Administration implemented in Docket UE-130536.

[13] *Id.*

- Rebates to customers over 18 months using \$8.6 million from the Renewable Energy Credit (REC) deferral account, lowering electric rates by \$5.9 million annualized or 1.2 percent.[14]
- An increase in LIRAP funding by \$0.2 million or 0.04 percent.

18 The Settlement reflects a net electric rate increase impact, including offsets from credits and refunds, of approximately \$11.9 million (2.48 percent).[15] The settling parties also agree that natural gas base revenues would increase by approximately \$8.5 million (5.58 percent overall) over existing 2014 levels.[16]

19 On November 12, 2014, Avista filed its updated power supply costs in compliance with the Settlement.[17] The Company's update reflects a total base power supply increase of approximately \$5.6 million that will be fully offset by an available credit from the ERM deferral balance.[18] Under the terms of the Settlement, if the update which includes updated natural gas and electricity market prices, new short term contracts for gas and electric, updated power and transmission service contracts, \$0.5 million power supply expense reduction, and \$0.7 million 2015 REC expenses, results in an increase in net power supply costs, the increase will be offset with available ERM deferral balance.[19]

20 Table A below, which was originally presented in the Joint Testimony in support of the Settlement,[20] has been modified to take into account the Company's updated power supply impacts as well as the Commission decision to double the Settlement's proposed LIRAP increases, which are discussed below.

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[14] *Id.*, ¶ 5(b).

[15] Joint Testimony, at 34:14.

[16] Settlement, ¶4.

[17] *Id.*, ¶6.

[18] November 2014 Update, Appendix 2.

[19] The ERM deferral balance as of June 30, 2014 is \$16.7 million, and is currently estimated to be \$13.9 million by December 31, 2014. Settlement, ¶6.

[20] Joint Testimony, at 34 at 34:1-14.

Revised Table A

Table A Rate Impacts Summary (000s of Dollars)				
Rate Changes Effective January 1, 2015	Electric		Natural Gas	
Rate Increase:				
Base General Increase	$7,000	1.40%	$8,500	5.30%
Base Power Supply Increase	5,295	1.10%		
Expiration of ERM Credits and BPA Transmission Refund	13,652	2.80%		
Sched 92 LIRAP Increase- Per Settlement	200	0.04%	214	0.14%
Additional Sched 92 LIRAP Change Per Commission	200	0.04%	214	0.14%
Sub-Total 2015 Increase	$26,347	5.38%	$8,928	5.58%
Rate Offset:				
New ERM Credits - Offset to 2015 Increase	(3,000)	-0.60%		
New ERM Credits - Offset to Power Supply Increase	(5,295)	-1.10%		
REC Credits Used to Offset 2015 Increase	(5,936)	-1.20%		
Sub-Total Offset to 2015 Rates	($14,231)	-2.90%		
Total 2015 Net Rate Increase including Offset	$12,116	2.48%	$8,928	5.58%

21 *Decision.* The Settlement's proposed rate increases result from compromises among the parties and reflect a negotiated, comprehensive package and were not necessarily determined by any agreed to specific ratemaking methodology. After extensive discussions and scrutiny, the parties were able to resolve their revenue requirement differences. In their Joint Testimony, the settling parties contend they have achieved a reasonable balancing of interests that is supported by sound analysis and sufficient evidence.[21] After consideration of all the relevant factors, we determine that the

[21] Joint Testimony at 1:16-24.

agreed revenue changes result in rates that are fair, just, reasonable, and sufficient, and that approval is in the public interest.

b. Decoupling[22]

22 The Settlement adopts revenue-per-customer full decoupling mechanisms for all fixed costs of Avista's electric and natural gas systems for the next five years.[23] The electric decoupling mechanism applies to revenues attributed to distribution systems costs as well as the fixed-cost portion of production costs.[24] The decoupling mechanisms commence on January 1, 2015, and terminate on December 31, 2019 and do not apply to certain customer classes including electric Schedules 25, and 41-48, or natural gas Schedules 112, 122, 132, and 146.[25] At hearing, Avista clarified that the decoupling deferral balances will accrue interest at the Federal Energy Regulatory Commission's (FERC) rate which is presently 3.25 percent.[26] The parties also offered clarifications regarding the decoupling mechanisms' earnings tests, conservation commitments, and third-party reviews, which are each described below.

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[22] Decoupling allows for the utility's recovery of the fixed costs it incurs independent of the amounts of electricity and natural gas it sells. Decoupling removes the so-called throughput incentive and is intended to promote more aggressive pursuit of cost-effective conservation.

[23] Settlement, ¶ 13. The decoupling mechanisms agreed to by the parties are based on Avista's original proposal, as modified by the Settlement. Ehrbar, Exh. No. PDE-1T, at 49-78. For a complete description and discussion of the Commission's decoupling policy see *In re WUTC Investigation into Energy Conservation Incentives,* Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, including Decoupling, To Encourage Utilities To Meet or Exceed Their Conservation Targets (Nov. 4, 2010) (Decoupling Policy Statement).

[24] Exh. No. 4, at 18-19. The mechanisms accomplish this by removing the fixed-cost portion of production costs from the ERM and the application of the Retail Revenue Credit in the decoupling mechanisms.

[25] Settlement, ¶ 13(b). The mechanism specified in this Settlement supersedes Avista's currently-effective natural gas decoupling mechanism. Exh. No. 4, at 17, note 13. The electric schedules omitted from the decoupling mechanism include Extra Large General Service (Schedule 25) and Street and Area Lighting (Schedules 41-48). Appendix 2 to Settlement at 3. The natural gas schedules omitted from the decoupling mechanism include Large General Service – Firm (Schedule 112), High Annual Load Factor Large General Service – Firm (Schedule 122), Interruptible Service (Schedule 132), and Transportation Service for Customer-owned Gas (Schedule 146).

[26] Norwood, TR 181:16-183:12; Ehrbar, Exh. No. PDE-9, at 4, line 35; Ehrbar, Exh. No. PDE-10, at 4, line 17. The Settlement did not specify if or when the interest rate will be adjusted to reflect the current FERC rate. Avista must update the interest rate to the current FERC rate on January 1 of each year the mechanisms are in effect.

23 The decoupling mechanisms include an earnings test that the settling parties intend to operate as a benefit to Avista's customers.[27] For example, if volumetric rates produce a surplus of revenue (i.e., sales revenue is above the product of the number of customers in the rate year times the revenue per customer), all of the surplus will be returned to the customers. In addition, if Avista's achieved ROR, as determined in the Company's annual Commission Basis Report exceeds 7.32 percent, the rebate to customers will be increased by half the revenue causing the excess ROR.[28]

24 Alternatively, if the decoupling mechanisms produce a revenue deficit (i.e., sales revenue is below the product of the number of customers in the rate year times the revenue per customer) and Avista's ROR is less than 7.32 percent, a bill surcharge is applied to customer bills to recover the full deficit amount. However, should that condition arise, to the extent Avista's ROR is greater than 7.32 percent, the surcharge on customer bills will be decreased by half the revenue causing the excess ROR.[29]

25 At hearing, the settling parties made three clarifications regarding the earnings test. First, Avista indicated that the Settlement's use of the term "one-half the rate of return in excess of 7.32%" in paragraph 13(c) has the same meaning as the term "one-half the *revenue causing* the excess ROR."[30] Second, Mr. Norwood clarified that if Avista's ROR is exactly 7.32 percent, there will be no adjustment to any surcharge or rebate.[31] Third, Mr. Norwood specified that the earnings test applies to all of the Company's earnings, and is not limited to the amount of decoupling surcharges or rebates.[32]

26 Avista also agrees in the Settlement to increase its electric conservation achievement by 5 percent over its biennial target.[33] At hearing, Avista specified that its 2014-2015 biennial conservation target is currently 64,956 megawatt-hours (MWh), 5 percent of

[27] Settlement, ¶ 13; TR 179:24-181:7 (exchange between Commissioner Goltz and Mr. Norwood); Exh. No. 4, at 46:10-15.

[28] Settlement, ¶ 13(c)(ii); TR 178:12-179:2.

[29] Settlement, ¶ 13(c)(iii).

[30] Norwood, TR 178:12-179:2; Settlement, ¶ 13(c).

[31] Norwood, TR 179:3-6.

[32] TR 179:24-181:7 (exchange between Commissioner Goltz and Mr. Norwood).

[33] Settlement, ¶ 13(f); RCW 19.285.040(1)(b).

which is 3,248 MWh.[34] Thus, the Settlement commits Avista to achieving 68,204 MWh of conservation in the 2014-2015 biennium. If the electric decoupling mechanism is in effect for any portion of a subsequent biennium, Avista commits to increasing its electric conservation achievement by 5 percent for the entire biennium. In other words, the 5 percent will not be reduced or pro-rated because decoupling is not in effect for the full biennium.[35] If this decoupling mechanism is in effect when Avista files a biennial conservation plan, that plan should state the 5 percent of additional conservation in MWh and the sum of Avista's biennial conservation target, plus this five percent commitment, in MWh.

27 Finally, Avista clarified that the Settlement obligates its shareholders to pay for a third-party evaluation of the decoupling mechanisms after three years.[36] The Settlement does not include specific requirements regarding the scope or contents of this evaluation, though Avista plans to consult with stakeholders as it develops the scope of the evaluation.[37] Mr. Schooley testified for Staff that the evaluation should include, at a minimum:

- an analysis of the mechanism's impact on conservation achievement,
- an analysis of the mechanism's impact on Company revenues (i.e., whether there has there been a stabilizing effect), and
- an analysis of the extent to which fixed costs are recovered in fixed charges for the customer classes excluded from the decoupling mechanisms.[38]

28 *Decision.* We find that the decoupling mechanisms presented in the Settlement are in the public interest, will promote the policy goals of increased conservation, and will result in fair, just, reasonable, and sufficient rates. We require that any review of the mechanisms should, at a minimum, include the three above-referenced analyses Mr. Schooley described. Additionally, we require Avista's decoupling evaluation to analyze if allowed revenues from the following rate classes are recovering their cost of service: residential class, non-residential class, and customers not subject to

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[34] Norwood, TR 179:16-23; *Avista Corp.*, Docket UE-132045, Order 01, Order Approving Avista Corporation's 2014-2023 Achievable Conservation Potential and 2014-2015 Biennial Conservation Target, Subject To Conditions, ¶ 9 (Dec. 19, 2013).

[35] Norwood, TR 181:11-15.

[36] Settlement Stipulation, ¶ 13(a); TR 186:2-13.

[37] Settlement Stipulation, ¶ 13(a); TR 184:25-185:15; TR 186:14-17.

[38] TR 186:18-187:3; TR 187:22-188:11.

decoupling. Finally, to ensure that the evaluation's scope is sufficient to provide the Commission and stakeholders with a meaningful review of the new mechanisms, we require Avista to:

- consult with its conservation advisory group in the development of the evaluation's request for proposals (RFP), and incorporate the input from its advisory group in a draft RFP;
- file a draft RFP for Commission approval that includes the scope of evaluation query, allowing sufficient time for Commission consideration; and
- consult with its conservation advisory group on the selection of the entity to perform the evaluation.

c. Power Supply

29 The base power costs for the Energy Recovery Mechanism (ERM) proposed in the Settlement are derived from the Company's power cost modeling with two additional out-of-model adjustments. At the time of the filing of the Settlement, the Company estimated base power costs to increase by approximately $6.3 million. The Settlement proposed that the Company re-run its power cost model on November 1, 2014.[39] At hearing, the Company agreed to include in this filing its level of planned hedging for the rate year, and its level of hedged positions included in the update base power costs.[40] On November 12, 2014, Avista filed updated power costs based on the November 1, 2014, model run.[41] That filing decreased total power supply costs to $5.6 million.

30 The Settlement provides two additional out-of-model adjustments to base power costs. First, base power costs will include 2015 renewable energy credit (REC) expenses.[42] In Avista's future filings, REC expenses will be included in base power

[39] *Id.* This update will provide more recent: three-month average natural gas and electricity prices, short-term contracts, transmission contract prices. *Id.* Based on this update, the Company will file with the Commission revised appendices to the Settlement Stipulation by November 17, 2014.

[40] Norwood, TR 233:22.

[41] November 2014 Update, Appendix 2; Settlement, ¶6.

[42] November 2014 Update, Appendix 2. Ms. Fisher provides Public Counsel's rationale for moving these expenses from the REC Revenue Tracker to the ERM. Fisher, Exh. No. LF-1CT, at 15:1-13.

supply costs and subject to the ERM's dead band and sharing bands.[43] Second, base power supply costs will also include Staff's proposed $500,000 expense reduction.[44]

31 Additionally, the settling parties agreed to allow Avista to recover the costs of improving dissolved oxygen levels in Lake Spokane.[45]

32 *Decision.* The proposed modifications are reasonable as a part of the whole Settlement. The ERM currently includes both fixed and variable costs. The Settlement removes fixed costs from the ERM and from the application of the Retail Revenue Credit adjustment.[46] The removal of fixed costs is appropriate because Avista will recover the fixed costs through the decoupling mechanism.[47]

d. Rate Spread/Rate Design

33 In the Settlement, the settling parties agreed to a uniform percentage increase for purposes of spreading among customer classes the final electric base revenue increase approved by the Commission, as well as the ERM rebate amount.[48] With regard to the natural gas increase, the settling parties did not agree on utilization of the results of a single cost of service study for purposes of allocating the final natural gas base revenue increase. Instead, the settling parties agreed to a negotiated rate spread specifically described and set forth in paragraph 15(a) of the Settlement.[49] The overall result is a modest increase in base rates across most schedules.[50]

34 *Decision.* The rate spread proposed in the Settlement results in fair, just, and reasonable allocation of costs among customer classes. The rate design proposed in the Settlement is basically unchanged from current rates, except for modest increases

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[43] *Id.*, ¶ 5(b).

[44] *Id.* Staff proposed this adjustment in Ball, Exhibit No. JBL-2, at 8:8-10:4.

[45] Settlement, ¶ 8.

[46] *Id.*, ¶ 13(e).

[47] Ball, Exhibit No. JLB-1T, at 10:1-13.

[48] Settlement, ¶ 14.

[49] *Id.*, ¶ 15.

[50] *Id.* At hearing, Avista clarified that the proposed basic charges for Schedules 111 and 121 remove the natural gas commodity costs, consistent with a prior Commission decision. Ehrbar, TR 229:22-230:9.

in basic charges in most schedules resulting in fair, just, reasonable, and sufficient rates.

e. LIRAP

35 The Settlement increases annual electric and natural gas LIRAP funding by twice the proposed Schedule 1 increase, for a total increase of $200,000 (5 percent) for electric LIRAP funding and $214,000 (11.6 percent) for natural gas LIRAP funding.[51] The Energy Project estimates that the increased LIRAP funding will provide assistance to an additional 400 households within the Company's service area.[52] At hearing, Avista and the Energy Project indicated that they would be amenable to the Commission approving even more LIRAP funding than set forth in the Settlement, by doubling the Settlement's proposed LIRAP increase.[53] Staff did not take a position, but did not oppose an increase in funding above the increase set forth in the Settlement.[54]

36 In Avista's 2012 general rate case, the Commission approved a multiparty settlement in which Avista committed to discuss potential program design options with Staff and other interested parties, and to propose changes to LIRAP in its next general rate case, if necessary.[55] In September 2013, Avista and Staff hosted a meeting on this topic with representatives of other investor-owned utilities, Commission Staff, the Energy Project, Public Counsel and other stakeholders.[56] In May 2014, Avista participated in a Commission-led workshop on low-income assistance programs.[57]

37 Avista did not propose any changes to LIRAP in this case, a decision Staff noted and opposed in its response testimony.[58] Staff proposed that Avista create a pilot program

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[51] Settlement, ¶ 18.

[52] Joint Testimony, 57:21-28:2.

[53] TR 253:17-25, 254:1-23 (Exchange between Commissioner Jones and Mr. Norwood) (September 23, 2014).

[54] Schooley, TR 254:11-13 (September 23, 2014).

[55] *Utilities & Transp. Comm'n v. Avista Corp.*, Dockets UE-120436 and UG-120437, Order 09 (December 26, 2012).

[56] Williams, Exh. No. JMW-1T, 5:14-19.

[57] *Id.*, 6:1-15.

[58] Kopczynski, Exh. No. DFK-1T, at 17:14-16. Williams, Exh. No. JMW-1T, 7:1-3.

offering rate discounts for low-income electric and natural gas customers,[59] and develop a data collection plan to determine the impact of low-income assistance in its service territory.[60]

38 The Settlement does not include any modifications to the design of LIRAP, or any additional low-income assistance programs. Instead, Avista agrees to continue to meet with Staff, the Energy Project, and other interested parties to develop mutually agreed-upon modifications or additions to LIRAP, and establish a filing schedule.[61]

39 We find that it is difficult for the parties to evaluate and manage LIRAP effectively due to insufficient data.[62] Staff recommended that the Commission facilitate more effective management of the program by ordering Avista to adopt express goals for LIRAP.[63] In the Settlement, the parties agree that the primary intention of any additions or modifications to LIRAP should be to keep low-income customers connected to services, and serve more customers who need assistance. [64] At hearing, the parties also expressed support for the goal of reducing low-income customers' energy burden.[65] We agree that it is important to identify program goals before attempting to redesign a program.[66] We find that the program goals discussed in the Settlement and at hearing are appropriate for Avista's low-income assistance programs.

40 The Settlement requires the parties to meet no later than 30 days after the effective date of this order, and at least every other month thereafter to explore additional program options.[67] The Settlement provides a filing deadline of June 1, 2015, for modifications to the existing LIRAP and June 1, 2016, for any additions to LIRAP.[68]

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[59] Williams, Exh. No. JMW-1T, 11:14-17, 17:9-10.

[60] *Id.*, 20:1-2.

[61] Settlement, ¶ 17.

[62] Williams, Exh. No. JMW-1T, 7:5-21, 8:1-10; Eberdt, Exh. No. CME-1T, 7:7-11.

[63] Williams, Exh. No. JMW-1T, 2:13-16.

[64] Settlement, ¶ 17.

[65] TR 271:1-272:20 (Exchange between Chairman Danner and Mr. Eberdt) (September 23, 2014).

[66] *Id.*

[67] Settlement, ¶ 17.

[68] *Id.*

41 The Settlement requires that Avista's shareholders pay for a third-party facilitator acceptable to all the parties to help manage this process.[69] We believe that the Community Action Agencies administering LIRAP are essential stakeholders in this process, and recognize that agencies located outside of the Spokane area may lack the resources needed to attend meetings.

42 *Decision.* We are concerned that the LIRAP funding set forth in the Settlement is not sufficient to meet existing and increasing low income customers' needs while also implementing needed program reforms and additions. At the public comment hearing in Spokane, we heard comments from several low-income customers and advocates stating that the overall rate increases in the Settlement would be burdensome to Avista's low-income customers. Specifically, the Spokane Neighborhood Action Partners (SNAP) stated that it did not support the Settlement, and encouraged us to consider further expanding LIRAP funding to serve more eligible customers.[70]

43 We find that the program goals discussed in the Settlement and at hearing are appropriate for Avista's low-income assistance program. When proposing additions to the LIRAP program or pilot projects, the parties should consider collecting appropriate data necessary both to evaluate the effectiveness of the program and inform ongoing policy discussions.[71]

44 Further, the record in this case shows that the poverty rate in Avista's service territory is higher than the statewide average,[72] and that the majority of customers eligible for LIRAP assistance are not served by the current program.[73] We are sensitive to the

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[69] Settlement, ¶ 17.

[70] Honekamp, TR 96:7-12, 98:1-5 (August 27, 2014). SNAP is an independent community action agency, represented by the Energy Project in this proceeding, and the largest of the community action agencies administering Avista's LIRAP. Mr. Eberdt, on behalf of the Energy Project, clarified at hearing that he didn't understand SNAP's objection to be anything other than concern "that there are a lot of people that are hurting and we're not getting to enough of them." Eberdt, TR 256:12-13.

[71] For example, Aging and Long-term Care of Eastern Washington proposes using the Elder Economic Security Index to qualify customers for low-income energy assistance instead of the Federal Poverty Guidelines; TR 66:5-7 (August 26, 2014); TR 261:22-264:20 (September 23, 2014).

[72] Honekamp, TR 93:4-22 (August 27, 2014).

[73] Eberdt, Exh. No. CME-1T, 7:8-18; Williams, Exh. No. JMW-1T, 7:8-10, 17-19; TR 261:15-20 (Exchange between Commissioner Goltz and Mr. Eberdt) (September 23, 2014).

needs of low income consumers and recognize that as energy prices increase to all consumers so must the available funding to those portions of the Company's customer base that are most affected by such increases. Although we are pleased the settling parties agreed to increase LIRAP funding for electric and natural gas consumers, we find the new proposed annual LIRAP funding levels to be inadequate and modify that portion of the Settlement. We therefore find that it is in the public interest to double the increase in LIRAP funding provided for in the Settlement, to a total increase of \$400,000 for electric LIRAP funding and \$428,000 for natural gas LIRAP funding.

45 We believe that it is in the public interest to avoid further delay in developing LIRAP program options to increase low income customer participation in the program. At hearing, the parties consented to file an agreed-upon proposal for modifications and additions by June 2015; or file competing proposals, if no consensus is reached.[74]

46 We therefore require Avista to file agreed-upon proposals for modifications *and additions* to LIRAP by June 1, 2015. We recognize that additional meetings or teleconferences may be necessary to comply with this timeline. If the parties do not reach consensus, they may file separate proposals containing program modifications and additions for the Commission's consideration by July 1, 2015.

47 Finally, at hearing, Avista agreed also to pay for the travel and lodging expenses of Community Action Agencies located in its service territory to participate in meetings.[75] We recognize and commend Avista's continued commitment to improving its low-income assistance programs, and we find that it is in the public interest for shareholders to bear these costs. In addition to paying for a third-party facilitator, we also require Avista to pay for any reasonable travel and lodging expenses incurred by Community Action Agencies participating in the meetings.

f. Attrition

48 In its filing, Avista maintains that it is experiencing attrition of earnings and that the decline in earnings is expected to be an ongoing phenomenon.[76] In support of its claim, the Company prepared an attrition study that trends the impact of attrition, by expense class, on its earnings, which it then uses to derive its revenue deficiency.

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[74] Jones, TR 268:8-16 (September 23, 2014).

[75] TR 269:2-12 (Exchange between Commissioner Jones and Ms. Gervais).

[76] Norwood, Exh. No. KON-1T, at 11:6-8.

Staff, in its response testimony, adopted a similar trending method identifying projected expense levels which Staff proposed the Commission use to set rates.[77] Public Counsel strongly opposed the trending methodology used by Avista and Commission Staff, arguing that, although it appears the trending approach used in the prior case "...is working and [is] quite precise," upon closer examination, the apparent precision is not due to the trending. Instead, Public Counsel suggests the attrition study results are due to the Company's decisions to accelerate capital expenditures before the end of the test period.[78] ICNU also opposed the use of the attrition study by pointing out that the proposed methodology has not been approved by the Commission nor has the Company satisfied the burden necessary to justify the Commission changing from its normal practice of setting revenue requirements.[79]

49 Since the parties do not agree that an attrition adjustment is included within the Settlement or whether an attrition adjustment is appropriate at all, we do not deliberate on the merits of any position on the issue presented in this case.[80] The settling parties do, however, recommend that the Commission establish a separate forum to discuss attrition and other general rate making policy issues.[81] Clearly there is a consensus among the parties regarding the need for a formalized discussion of attrition along with other possible ratemaking mechanisms that may address attrition's effects on earnings.[82]

50 In addition to the forum, Avista agrees to provide semi-annual reporting of 2014 and 2015 capital expenditures with actual data by expenditure request, in the categories provided in its *pro forma* "cross check" plant adjustments.[83] The settling parties agree to meet no later than January 31, 2015, to establish any additional details of the capital reporting requirements.[84]

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[77] McGuire, Exh. No. CRM-1CT.

[78] Dittmer, Exh. No. JRD-1CT, at 25:3-18.

[79] Mullins, Exh. No. BGM-1T, at 2:15-26.

[80] Settlement, ¶ 11.

[81] *Id.*, ¶ 21.

[82] Fisher, TR 213:11-18.

[83] Settlement, ¶ 20.

[84] *Id.*

51 *Decision.* We direct Commission Staff to open an investigatory docket for the purpose of convening a forum to address attrition consistent with the Settlement. We expect the forum to be inclusive, open to participation by not only the parties in this proceeding but also the broader community of commission-regulated utility companies and interested consumer groups.

g. Cost of Capital

52 The parties have not formally agreed to capital structure ratios or the elements that make up the Company's authorized cost of capital including ROE or overall ROR.[85] However, despite the lack of formal agreement on the individual components of cost of capital, the parties have agreed to a 7.32 percent ROR for certain purposes including the determination of Allowance for Funds Used During Construction (AFUDC).[86] The Settlement also uses a 7.32 percent ROR as the potential trigger for future earnings tests associated with any decoupling deferral based on the company's reported annual earnings.[87] Appropriately, the Settlement recognizes that the 7.32 percent ROR will be changed to reflect any future ROR authorization that may be established by the Commission.[88]

53 *Decision.* The settling parties note that they undertook extensive negotiations over many components of the Company's filing including the various components of cost of capital. The settlement discussions produced a reasonable balancing of interests with each party making certain concessions on matters which would not have been resolved or agreed to if the parties were to proceed to evidentiary hearings.[89] We accept the 7.32 percent ROR to be used for AFUDC purposes and for the earnings test to be applied for decoupling purposes.

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[85] Settlement, ¶ 10 and 24 and Joint Testimony, Exh. No. 4, at 1:19-20, 11:14-19 and 43:3-6.

[86] Settlement, ¶ 10, n. 7.

[87] Settlement, ¶ 13 Part c.

[88] Settlement, ¶ 13 Part c.ii.1, n. 10.

[89] Joint Testimony, Exh. No. 4, at 11, 14-19.

FINDINGS OF FACT

54 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

55 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including gas and electrical companies.

56 (2) Avista is a "public service company," an "electrical company," and "gas company" as those terms are defined in RCW 80.04.010 and used in Title 80 RCW. Avista provides electric and natural gas utility service to customers in Washington.

57 (3) On February 4, 2014, Avista filed certain revisions to its currently effective tariffs for electric and natural gas services.

58 (4) The Commission suspended the operation of the proposed tariff revisions pending an investigation and hearing and consolidated the Company's proposed tariff revisions.

59 (5) On August 18, 2014, the parties filed a Settlement Stipulation that, if approved, would resolve the contested issues raised in Avista's initial filing.

60 (6) On September 23, 2014, the Commission convened a settlement hearing to hear the parties' views on why the Settlement should be approved and adopted and to clarify portions of the Settlement.

CONCLUSIONS OF LAW

61 Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

62 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings.

63 (2) The rates proposed by tariff revisions filed by Avista on February 4, 2014, and suspended by prior Commission order, were not shown to be fair, just or reasonable and should be rejected.

64 (3) Avista's existing rates for electric service provided in Washington are insufficient to yield reasonable compensation for the service rendered.

65 (4) Avista requires relief with respect to the rates it charges for electric and natural gas services provided in Washington.

66 (5) The Settlement filed by the parties to this proceeding on August 18, 2014, and revised on September 8, 2014, if approved with conditions, would result in rates that are fair, just, reasonable, and sufficient, and are neither unduly preferential nor discriminatory.

67 (6) The Settlement, which is attached to this Order as Appendix A, and subject to the conditions in paragraph 5, should be approved by the Commission as a reasonable resolution of the issues presented.

68 (7) The Low Income Rate Assistance Program portion of Schedules 91 and 191 should be increased in Avista's electric and natural gas tariffs to levels double those listed in the Settlement.

69 (8) The Settlement is lawful and approval and adoption of it, subject to the conditions set forth in paragraph 5, is in the public interest.

70 (9) Avista should be required to make such compliance and subsequent filings as are necessary to effectuate the terms of this Order.

71 (10) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

72 (11) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS:

73 (1) The proposed tariff revisions Avista Corporation, d/b/a Avista Utilities, filed on February 4, 2014, and suspended by prior Commission order, are rejected.

74 (2) The Settlement filed by the parties on August 18, 2014, and revised on September 8, 2014, which is attached to this Order as Appendix A and subject to the conditions listed in paragraph 5, is approved and adopted as being in the public interest.

75 (3) Avista is required to make a compliance filing including such new and revised tariff sheets as are necessary to implement the requirements of this Order. The stated effective date of the revised tariff sheets shall be January 1, 2015, in accordance with the terms of the Settlement. Avista must make its compliance filing, assuming conditions are accepted, as soon as possible, but no later than December 15, 2014, , to afford Staff a reasonable opportunity to review the filing and to inform the Commission whether Staff finds the revised tariff sheets fully conform to the requirements of this Order.

76 (4) Within 10 days from the date of this Order, Avista must file notification with the Commission if it accepts the conditions imposed by the Commission.

77 (5) The Commission Secretary is authorized to accept by letter, with copies to all parties to this proceeding, such filings as Avista makes to comply with the terms of this Order.

78 (6) The Commission retains jurisdiction over the subject matters and parties to this proceeding to effectuate the terms of this Order.

Dated at Olympia, Washington, and effective November 25, 2014.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chairman

PHILIP B. JONES, Commissioner

JEFFREY D. GOLTZ, Commissioner

NOTICE TO PARTIES: This is a Commission Final Order. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 and WAC 480-07-870.

APPENDIX A

SETTLEMENT STIPULATION
DOCKETS UE-140188 and UG-140189 (consolidated)

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. AVISTA CORPORATION d/b/a AVISTA UTILITIES Respondent.	)	DOCKETS UE-140188 and UG-140189 (*Consolidated*) FULL SETTLEMENT STIPULATION

I. PARTIES

1. This Settlement Stipulation is entered into by Avista Corporation ("Avista" or the "Company"), the Staff of the Washington Utilities and Transportation Commission ("Staff"), the Public Counsel Section of the Washington Office of Attorney General ("Public Counsel"), Northwest Industrial Gas Users ("NWIGU"), Industrial Customers of Northwest Utilities ("ICNU"), and The Energy Project, jointly referred to herein as the "Parties." Accordingly, this represents a "full settlement" under WAC 480-07-730. The Parties, representing all who have intervened or appeared in these dockets, agree that this Settlement Stipulation (hereinafter "Settlement" and/or "Stipulation") is in the public interest and should be accepted by the Commission as a full resolution of the known issues in these dockets. The Parties understand this Settlement Stipulation is subject to approval of the Washington Utilities and Transportation Commission (the "Commission").

II. INTRODUCTION

2. On February 4, 2014, Avista filed with the Commission certain tariff revisions designed to increase general rates for electric service (Docket UE-140188) and natural gas service (Docket UG-140189) in the State of Washington. Avista requested an increase in electric base rates of $18.2 million, or 3.8 percent from 2014 levels, and an increase in natural gas base rates of $12.1 million, or 8.1 percent from 2014 levels. On March 10, 2014, the Commission entered Order No. 03 suspending the tariff revisions and setting Dockets UE-140188 and UG-140189 for hearing and determination pursuant to WAC 480-07-320. Representatives of all Parties appeared at Settlement Conferences held on July 7, 2014 and August 4, 2014, which were held for the purpose of narrowing or resolving the contested issues in this proceeding. Subsequent discussions led to this Settlement Stipulation.

3. The Parties have reached a settlement of the known issues as among themselves in this proceeding and wish to present their agreement for the Commission's consideration and approval. The Parties, therefore, adopt the following Settlement Stipulation in the interest of reaching a fair disposition of the issues in this proceeding.

III. AGREEMENT

A. Revenue Increases and Rate Effective Dates

4. Increases in Base Rates. The Parties agree that, effective with service on and after January 1, 2015, Avista shall be authorized to implement base rate changes designed to increase its annual revenues, over existing 2014 revenues, from Washington electric customers by $7.0 million (approximately 1.4 percent overall), and from Washington natural gas customers by $8.5 million (approximately 5.6 percent overall). The Parties agree that a credit of $3.0 million from the existing Energy Recovery Mechanism (ERM) deferral balance will be returned to electric customers to mitigate the 2015 rate increase for calendar year 2015, such that the net overall electric rate increase

to customers in 2015 is 0.8 percent overall.

5. January 1, 2015 Electric Billing Changes and REC Revenue Mechanism.

a) Effective January 1, 2015, the current ERM and BPA credits will expire resulting in an overall increase of 2.8%.[1]

b) The Company will rebate approximately $8.6 million of Renewable Energy Credit ("REC") revenues over 18 months ($5.9 million annualized, or 1.3 percent)[2] / [3]. Going forward, the Parties agree that the costs associated with RECs purchased to comply with the Washington Energy Independence Act will be excluded from the REC tracking mechanism,[4] and will be included in the determination of base power supply costs in a general rate case. Any differences in costs from that included in base power supply costs will be tracked through the ERM, and subject to the existing dead band and sharing bands.

6. Power Supply Update. Effective January 1, 2015, the Parties agree to adjust, up or down, Washington electric revenues related to updated power supply costs. The current estimate is a $6.3 million increase for power supply costs. A new power supply model run on November 1, 2014, will determine the final power cost increase and ERM baseline. As in past proceedings, and as noted in Staff testimony (Ball Exhibit No. JLB-1T, page 6), the purpose of this power supply update will be to: 1) update the three-month average of natural gas and electricity market prices; 2) include new short-term contracts for gas and electric; and 3) update or correct power and transmission service contracts for the 2015 rate year. Staff's $500,000 power supply reduction to expense will be

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[1] Included in present billing rates is a refund of approximately $9.0 million from the Energy Recovery Mechanism Schedule 93 (as approved in Docket No. UE-120436), and a refund of approximately $4.3 million from the Bonneville Power Settlement (Docket No. UE-130536), both expiring on January 1, 2015.

[2] Page 4 of Appendix 2 shows the rate spread and cents per kWh rate for the REC Revenue rebate.

[3] The Parties agree to the removal of certain 2015 REC expenses of $725,000 in the determination of the REC revenue rebate, and the use of an after-tax cost of capital interest rate (6.34%) on the rebate balance as proposed by Public Counsel and Staff, and agree to the rate spread (E02 allocator - Generation Level Consumption) as proposed by Staff.

[4] The mechanics of the REC tracking mechanism are included in Mr. Johnson's testimony, WGJ-1T, pages 15-16.

reflected in the updated net power supply costs. In addition, the 2015 REC expenses of $725,000, excluded from the REC rebate calculation, will also be added to the updated net power supply costs.

The net power supply costs resulting from this power supply update, including the two adjustments of $500,000 and $725,000, referenced immediately above, will be compared with the net power supply costs in Avista's original filing in this case to determine the adjustment to Washington revenues on January 1, 2015 related to the power supply update. The net power supply costs in Avista's original filing are shown in Appendix 3.[5]

The updated level of net power supply costs will also be used to determine the new base set of power supply revenues and expenses for ERM calculations beginning January 1, 2015, as further explained in Section B below.

If the November 2014 power supply update results in an increase in net power supply costs, the increase will be offset with available ERM deferral balance dollars for the 12-month period January 1, 2015 through December 31, 2015.[6]

The Company will file on or before November 17, 2014, revisions to the appendices to this settlement stipulation to reflect the power supply update. The Parties are free to seek discovery on, and examine the prudence of, the updated power supply items identified above.

7. Natural Gas Project Compass Deferral. The Parties agree the natural gas revenue requirement associated with the Project Compass Customer Information System for the calendar year 2015 will be deferred for recovery in a future proceeding, based on the actual costs of the Project

[5] These net power supply costs, from the original filing, have been adjusted to reflect 2015 system retail loads, per Paragraphs 9 and 12 of this settlement stipulation.

[6] The ERM deferral balance as of June 30, 2014 is $16.7 million, and is currently estimated to be $13.9 million by December 31, 2014.

at the time the Project goes into service. The carrying charge on the deferral balance will be 3.25%. An estimate of the revenue requirement, for illustrative purposes only, is provided in Appendix 1.

8. Lake Spokane Deferral. In Docket No. UE-131576, Order No. 01, the Company received approval to defer and seek recovery in its next general rate case Washington's share ($871,000) of costs related to the improvement of dissolved oxygen levels in Lake Spokane. The agreed upon revenue increase reflects the amortization of this balance over a three-year period beginning January 1, 2015, with no carrying charge.

9. 2015 Billing Determinants. The Parties agree the Washington electric and natural gas revenue increases will be spread using the January 2015 through December 2015 billing determinants.

10. Cost of Capital. The Parties have not agreed on specific capital structure ratios or cost of capital components.[7] The agreed-upon revenue increases reflect a reduction in risk associated with the adoption of decoupling.

11. Attrition. While the Parties agree to the level of electric and natural gas revenue increases, there is disagreement on the use of an attrition adjustment in the determination of the revenue increases.[8]

B. Other Settlement Components

12. ERM Authorized Amounts.

a) For purposes of calculating the monthly ERM entries beginning January 1, 2015, the level of power supply revenues, expenses, retail load, and retail revenue credit for the ERM will be

[7] A 7.32% rate of return, however, will be used for "Allowance For Funds Used During Construction" (AFUDC) and other purposes.

[8] While the Company and Staff support the use of an attrition adjustment to achieve reasonable and sufficient rates, ICNU, Public Counsel and NWIGU do not agree that an attrition adjustment is warranted in this case.

based on the November 1, 2014 updated power supply model run discussed in Section A, Paragraph 6. Appendix 3 includes the level of power supply revenues, expenses, retail load, and retail revenue credit as originally filed by Avista, with the power supply expenses and retail load adjusted to reflect 2015 retail loads. The retail load in the new ERM base numbers will be based on 2015 billing determinants, per Paragraph 9 above.

b) The Retail Revenue Credit (RRC) will be based on Staff's proposed variable rate (revised to exclude all production plant), which will be based on ERM-related FERC accounts. The same RRC will be used for both the ERM calculations and the electric Decoupling Mechanism starting January 1, 2015 (described below).

13. Electric and Natural Gas Decoupling.

a) The electric and natural gas Decoupling Mechanisms illustrated in Appendices 4 and 5 will commence concurrent with the natural gas and electric rate changes January 1, 2015.[9] Per the Company's testimony, the length of the decoupling mechanisms is five years, with a third-party evaluation of the mechanisms paid for by Avista, to be completed following the end of the third full-year.

b) Electric Schedules 25 and 41-48 are excluded from the decoupling mechanism. Natural Gas Schedules 112, 122, 132 and 146 are excluded from the decoupling mechanism.

c) The Company will perform an annual earnings test as follows:

i. The earnings test will be based on the Company's year-end Commission Basis Reports ("CBR") stated on an average-of-monthly-averages ("AMA") basis, prepared in accordance with WAC 480-90-257 and 480-100-257 (Commission Basis Report). This report is prepared using actual recorded results of electric or natural gas operations and rate base, adjusted for any material out-of-period, non-operating, nonrecurring, and extraordinary items or any other item that materially

[9] Per the Company's filed testimony (PDE-1T, p. 78), the existing partial natural gas decoupling mechanism will be terminated effective January 1, 2015, and the Company will transfer any remaining deferral balance into the new mechanism.

distorts reporting period earnings and rate base. These adjustments have been consistently made by the Company when preparing past CBRs and are consistent with the adjustments described in paragraph (2) (b) of WAC 480-90-257 and 480-100-257 (Commission Basis Report). The CBR includes normalizing adjustments, such as adjustments to power supply-related revenues and expenses to reflect operations under normal conditions. For the earnings test, the decoupling accounting entries adjust revenues from a kilowatt-hour ("kWh") sales basis to a revenue per customer basis. The CBR will not include any annualizing or pro forma adjustments.

ii. Should the Company have a decoupling rebate balance at year-end, the entire rebate will be returned to customers.
   1) If the CBR earned return exceeds 7.32%, the rebate will be increased by one-half the rate of return in excess of 7.32%.[10]

iii. Should the Company have a decoupling surcharge balance at year-end:
   1) If the CBR earned return is less than 7.32%, no adjustment is made to the surcharge, if any, recorded for the year.
   2) If the CBR earned return exceeds 7.32%, the surcharge recorded for the year will be reduced, or eliminated, by one-half the rate of return in excess of 7.32%.

d) The calculation of power supply related revenue that will be deducted from total revenues prior to calculating revenue per customer is as follows: Authorized Power Supply Year kWhs * Retail Revenue Credit.

e) The Retail Revenue Credit is based on Staff's proposed variable rate (revised to exclude all production plant), which is based on ERM-related FERC accounts. The same credit will be used for ERM calculations.

f) The Company agrees to increase its electric energy conservation achievement by 5% over the conservation target approved by the Commission, beginning with the 2014-2015 biennial target.

g) A decoupling surcharge cannot exceed a 3% annual rate adjustment, and any unrecovered

[10] The 7.32% figure used for the earnings test will be adjusted to reflect any subsequent rates of return approved by the Commission during the term of the Decoupling Mechanisms.

balances will be carried forward to future years for recovery. There is no limit to the level of the decoupling rebate.

h) Appendix 4 contains the calculations for determining the baseline allowed revenue per customer for the electric decoupling mechanism. The final form of Appendix 4 will be filed on or before November 17, 2014, to reflect changes from the November 1, 2014 power supply update.

i) Appendix 5 contains the calculations for determining the baseline allowed revenue per customer for the natural gas decoupling mechanism.

C. Rate Spread/Rate Design

14. Electric Rate Spread/Rate Design

a) Electric Cost of Service/Rate Spread – The Parties agree to a uniform percentage of revenue increase for purposes of spreading the base revenue increase of $7.0 million, as well as the $3.0 million ERM offset, as shown on Page 1 of Appendix 2.[11]

b) The Parties agree that the revenue change related to the updated power supply costs discussed in Section A above, as well as the ERM offset, will be spread on a uniform percentage basis. Within each electric rate schedule, the revenue increase from the updated power supply costs and the ERM offset will be applied on a uniform percentage basis to the variable energy blocks.

c) Electric Rate Design, shown on Page 2 of Appendix 2:

(i.) The Residential Basic Charge (Schedule 1) increases from $8 per month to $8.50 per month.

[11] Page 3 of Appendix 2 shows the revenue spread of the $3.0 million to each rate schedule.

(ii.) For the rate design of Schedule 1, the revenue applicable to the volumetric rates is spread on a uniform percentage basis.

(iii.) For the rate design of Schedule 25, the demand charge for the first 3,000 kVa or less increases from $15,000 to $21,000 per month. In addition, the variable demand charge increases from $5.25 to $6.00 per kVa over 3,000 per month. The remaining revenue change applicable to Schedule 25 will be spread on a uniform percentage basis to the three energy block rates.

(iv.) The Rate Design for all other Schedules will be as follows:

- Schedules 11/12 will have an increase in the Basic Charge from $15.00 to $18.00 per month, and a uniform percentage rate change to blocks. In addition, the demand charge will remain at $6.00 per kilowatt in excess of 20 kW per month.
- Schedules 21/22 will have an increase in the Basic Charge from $450 to $500 per month, for the first 50kW or less, and a uniform percentage increase to all blocks for the remaining revenue increase. In addition, the demand charge will remain at $6.00 per kilowatt for all demand in excess of 50 kW per month.
- Schedules 31/32 will have an increase in the Basic Charge from $15.00 to $18.00 per month, and there will be a uniform percentage increase to all blocks for the remaining revenue increase applicable to the schedule.
- Street and Area Lighting (Schedules 41-48) will see a uniform percentage increase.

15. Natural Gas Rate Spread/Rate Design:

a) Natural Gas Cost of Service/Rate Spread – The rate spread for natural gas is shown on Page 6 of Appendix 2. While the Parties do not agree on the results of a single cost of service study, for purposes of settlement the Parties agree to spread the revenue increase as follows:

	Revenue	Percentage
Schedule 101	$6,581,000	6.00%
Schedule 111/112	$1,515,000	4.40%
Schedule 121/122	$181,000	4.60%
Schedule 131/132	$43,000	5.60%
Schedule 146	$180,000	7.40%
	$8,500,000	**5.60%**

b) Natural Gas Rate Design, shown on Page 7 of Appendix 2:

(i.) The Basic Charge for Schedule 101 will increase from $8 per month to $9 per month.

(ii.) For Schedule 146, the monthly basic charge will increase from $400 to $500 per month, and the remaining revenue increase will be spread on a uniform percentage basis to all blocks.

(iii.) The Rate Design for other Schedules will be as follows:

- Schedule 111 will have an increase in the monthly Minimum Charge based on Schedule 101 rates (breakeven at 200 therms), and a uniform percentage increase to all blocks.
- Schedule 121 will have an increase in the monthly Minimum Charge based on Schedule 101 rates (breakeven at 500 therms), and a uniform percentage increase to blocks two through four.
- Schedule 131 will have a uniform percentage increase to all blocks.

D. Service Quality and Reliability Program:

16. Avista agrees to meet with Staff and interested parties to develop and implement appropriate service quality metrics, customer guarantees and reporting, with the agreed upon tariff revisions filed on or before June 1, 2015, with a program in place on July 1, 2015.

E. Low Income Rate Assistance Program (LIRAP) Modifications:

17. The Company, the Energy Project, Commission Staff, other interested parties and the agencies that deliver the LIRAP program shall meet to explore additional program options and develop mutually agreed to modifications or additions to the LIRAP program. The primary intention of either additions or modifications is to keep low-income customers connected to service while serving more customers who need assistance. Modifications would entail changes to the existing bill assistance structures, e.g., continuing to serve LIRAP Heat applicants through the summer. Additions are changes that augment the existing programs with new service offerings, such as a targeted rate discount or arrearage management program. Meetings will begin no later than 30 days after the Commission accepts any settlement that covers this issue in this case. A third party facilitator acceptable to all the parties will be used and will be paid for by Avista shareholders. Meetings will be held at least bi-monthly or more frequently until completion. The Company will file mutually agreed upon modifications to the existing LIRAP program with the Commission by June 1, 2015, including a proposal to implement such changes in time for the fall 2015 bill assistance season. Any mutually agreed to addition(s) to LIRAP will be filed by June 1, 2016 for implementation on or after October 1, 2016.

F. LIRAP Funding:

18. The Parties accept the Energy Project and Staff's proposal to increase Electric LIRAP Funding by twice the Schedule 1 increase ($200,000 or 5.0 percent), and Natural gas LIRAP Funding

by twice the Schedule 101 increase ($214,000 or 11.6 percent. In addition, for Schedule 25, the Parties agree that the LIRAP rate will apply to the first and second energy blocks. LIRAP revenues previously collected from the third block will be spread to all schedules, including the first two blocks of Schedule 25, on a uniform percentage of current LIRAP funding levels. The changes to electric LIRAP funding can be found on Page 5 of Appendix 2, and the changes to natural gas LIRAP funding can be found on Page 8 of Appendix 2.

G. Bonneville Power Residential Exchange Program Interest Rate:

19. Related to the carrying charge on the Residential Exchange deferral balance, the Company agrees, effective January 1, 2015, to use a money market carrying charge instead of the Company's average cost of debt.

H. Other Issues:

20. The Company agrees to provide detailed semi-annual reporting of 2014 and 2015 capital expenditures with actual data by expenditure request, in the categories provided in its pro forma "cross check" plant adjustments. The Parties agree to meet and confer by no later than January 31, 2015 to establish any additional details of the capital reporting requirements.

21. The Parties recommend the Commission provide a separate forum to discuss attrition and other rate making policy issues, to include participation by Commissioners, and interested parties.

22. The Parties agree to address in the next general rate case alternative methods to rebate or recover ERM balances.

IV. EFFECT OF THE SETTLEMENT STIPULATION

23. Binding on Parties. The Parties agree to support the terms of the Settlement Stipulation throughout this proceeding, including any appeal, and recommend that the Commission issue an order adopting the Settlement Stipulation contained herein. The Parties understand that this

Settlement Stipulation is subject to Commission approval. The Parties agree that this Settlement Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements and documents disclosed in the negotiation of this Settlement Stipulation shall not be admissible evidence in this or any other proceeding.

24. Integrated Terms of Settlement. The Parties have negotiated this Settlement Stipulation as an integrated document. Accordingly, the Parties recommend that the Commission adopt this Settlement Stipulation in its entirety. Each Party has participated in the drafting of this Settlement Stipulation, so it should not be construed in favor of, or against, any particular Party.

25. Procedure. The Parties shall cooperate in submitting this Settlement Stipulation promptly to the Commission for acceptance. Each Party shall make available a witness or representative in support of this Settlement Stipulation. The Parties agree to cooperate, in good faith, in the development of such other information as may be necessary to support and explain the basis of this Settlement Stipulation and to supplement the record accordingly.

26. Reservation of Rights. Each Party may offer into evidence its prefiled testimony and exhibits as they relate to the issues in this proceeding, together with such evidence in support of the Stipulation as may be offered at the time of the hearing on the Settlement. If the Commission rejects all or any material portion of this Settlement Stipulation, or adds additional material conditions, each Party reserves the right, upon written notice to the Commission and all parties to this proceeding within seven (7) days of the date of the Commission's Order, to withdraw from the Settlement Stipulation. If any Party exercises its right of withdrawal, this Settlement Stipulation shall be void and of no effect, and the Parties will support a joint motion for a procedural schedule to address the issues that would otherwise have been settled herein.

27. Advance Review of News Releases. All Parties agree:

a. to provide all other Parties the right to review in advance of publication any and all announcements or news releases that any other Party intends to make about the Settlement Stipulation. This right of advance review includes a reasonable opportunity for a Party to request changes to the text of such announcements. However, no Party is required to make any change requested by another Party; and,

b. to include in any news release or announcement a statement that Staff's recommendation to approve the settlement is not binding on the Commission itself. This subsection does not apply to any news release or announcement that otherwise makes no reference to Staff.

28. No Precedent. The Parties enter into this Settlement Stipulation to avoid further expense, uncertainty, and delay. By executing this Settlement Stipulation, no Party shall be deemed to have accepted or consented to the facts, principles, methods or theories employed in arriving at the Settlement Stipulation, and, except to the extent expressly set forth in the Settlement Stipulation, no Party shall be deemed to have agreed that such a Settlement Stipulation is appropriate for resolving any issues in any other proceeding.

29. Public Interest. The Parties agree that this Settlement Stipulation is in the public interest.

30. Execution. This Settlement Stipulation may be executed by the Parties in several counterparts and as executed shall constitute one Settlement Stipulation.

Entered into this 18 ~~th~~ day of August 2014.

Company: By: ______________________
David J. Meyer
VP, Chief Counsel for Regulatory and Governmental Affairs

Staff: By: ______________________
Brett P. Shearer
Assistant Attorney General
Patrick J. Oshie
Assistant Attorney General

Public Counsel: By: ______________________
Lisa Gafken
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The Energy Project:	By: ______________________ Ronald Roseman Attorney at Law

APPENDIX 1

Avista Utilities
Project Compass
WA Natural Gas Revenue Requirement (1)

Line No.		Software (FERC 303100)	Hardware (FERC 391100)	Total
1	Depreciation Expense	$ 5,320,106	$ 515,584	$ 5,835,690
2	Property Tax @ 1.5% of Gross Plant, excluding software	-	116,006	116,006
3	Total Expenses	5,320,106	631,590	5,951,696
4	Net Operating Income Before FIT	(5,320,106)	(631,590)	(5,951,696)
5	FIT Benefit of Depreciation and Property Tax	1,862,037	221,057	2,083,094
6	FIT Benefit of Interest Expense	724,635	70,226	794,861
7	Net Operating Income Requirement	$ (2,733,434)	$ (340,308)	$ (3,073,742)
8	Net Plant (2)	$ 79,801,595	$ 7,733,761	$ 87,535,357
9	Accumulated Depreciation (AMA)	(2,660,053)	(257,792)	(2,917,845)
10	Accumulated DFIT (AMA)	(3,723,609)	(360,864)	(4,084,473)
11	Net Rate Base	73,417,933	7,115,105	80,533,039
12	Rate of Return	7.32%	7.32%	7.32%
13	Return on Rate Base	$ 5,374,193	$ 520,826	$ 5,895,018
14	Net Operating Income Requirement including Return	$ 8,107,627	$ 861,133	$ 8,968,760
15	WA Natural Gas Conversion Factor	0.62088	0.62088	0.62088
16	Revenue Requirement	$ 13,058,283	$ 1,386,956	$ 14,445,239
17	WA Natural Gas Allocator	14.31%	14.31%	
18	Revenue Requirement - WA Natural Gas Share (3) (4)	$1,868,446	$198,453	$2,066,899
	Tax benefit of debt			
19	Net rate base per above	$73,417,933	$7,115,105	$80,533,039
20	Debt cost component	2.82%	2.82%	2.82%
21	Debt cost	$2,070,386	$200,646	$2,271,032
22	Federal income tax rate	35%	35%	35%
23	Tax benefit of debt cost	$724,635	$70,226	$794,861

Notes:

(1) Information provided for illustrative purposes. Amounts will be based on actual costs of the Project at the time the Project goes into service.

(2) Project Compass Costs include the following:

	Software	Hardware	Total
Total Cost	$ 89,113,570	$ 8,813,430	$ 97,927,000
Less: Maximo Project (#09905700) transferred to Plant in Sept. 2013	9,311,975	1,079,669	10,391,643
	$ 79,801,595	$ 7,733,761	$ 87,535,357

(3) In service date of January 1, 2015 was used to compute 2015 average rate base. If the in-service date is later than January 1, 2015 the revenue requirement for 2015 will be lower.

(4) The carrying charge on the deferral balance will be 3.25%.

SECOND REVISED APPENDIX 2

Updated November 2014

AVISTA UTILITIES
WASHINGTON ELECTRIC
PROPOSED INCREASE BY SERVICE SCHEDULE
12 MONTHS ENDED DECEMBER 31, 2015
(000s of Dollars)

Updated to reflect November 2014 Power Supply update & ERM offset.

No.	Type of Service	Schedule Number	Base Tariff Revenue Under Present Rates(1)	Base General Increase	Base Power Supply Increase	Base Tariff Revenue Under Proposed Rates(1)	Base Tariff Percent Increase	Sch.93 ERM Decrease	Sch.98 REC Revenue Decrease	Expiration of 2014 ERM/BPA Decrease	Sch. 92 LIRAP Increase	Net General & Sch 92/93/94/98 Increase	Percent Increase on Billed Revenue(2)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Residential	1	$214,476	$3,061	$2,311	$219,848	2.5%	-$3,625	-$2,535	$6,021	$174	$5,407	2.6%
2	General Service	11/12	$69,493	$989	$749	$71,231	2.5%	-$1,174	-$610	$1,717	$60	$1,731	2.5%
3	Large General Service	21/22	$127,831	$1,828	$1,377	$131,036	2.5%	-$2,160	-$1,523	$3,549	$108	$3,179	2.5%
4	Extra Large General Service	25	$61,637	$877	$667	$63,181	2.5%	-$1,042	-$1,098	$1,937	($156)	$1,185	1.9%
5	Pumping Service	30/31/32	$10,525	$149	$115	$10,789	2.5%	-$178	-$145	$284	$8	$234	2.2%
6	Street & Area Lights	41-48	$6,871	$96	$76	$7,043	2.5%	-$116	-$27	$144	$6	$180	2.5%
7	Total		$490,833	$7,000	$5,295	$503,128	2.5%	-$8,295	-$5,936	$13,652	$200	$11,916	2.4%

* All revenue based on 2015 billing determinants

(1) Excludes all present rate adjustments: Schedule 59 (BPA Residential Exchange), Schedule 91 (DSM Adjustment), Schedule 92 (LIRAP Adjustment), Schedule 93 (Energy Recovery Mechanism), and Schedule 94 (BPA Transmission Revenue).

(2) Includes all rate adjustments: Schedule 59 (BPA Residential Exchange), Schedule 91 (DSM), Schedule 92 (LIRAP), Schedule 93 (ERM), Schedule 94 (BPA Transmission Revenue), and Schedule 98 (REC Revenue Rebate).

AVISTA UTILITIES
WASHINGTON ELECTRIC
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

Updated to reflect November 2014 Power Supply update & ERM offset.

Type of Service	Base Tariff Sch. Rate	Present Other Adj.(1)	Present Billing Rate	General Rate Inc/Dec	Sch. 93/98 ERM/REC Decrease	Sch. 93/94 ERM/BPA Increase	Sch. 92 LIRAP Increase	Proposed Billing Rate	Proposed Base Tariff Rate
Total Profo (a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Residential Service - Schedule 1									
Basic Charge	$8.00		$8.00	$0.50				$8.50	$8.50
Energy Charge:									
First 800 kWhs	$0.07369	($0.00214)	$0.07155	$0.00156	($0.00253)	$0.00247	$0.00007	$0.07312	$0.07525
800 - 1,500 kWhs	$0.08573	($0.00214)	$0.08359	$0.00182	($0.00253)	$0.00247	$0.00007	$0.08542	$0.08755
All over 1,500 kWhs	$0.10050	($0.00214)	$0.09836	$0.00214	($0.00253)	$0.00247	$0.00007	$0.10051	$0.10264
General Services - Schedule 11									
Basic Charge	$15.00		$15.00	$3.00				$18.00	$18.00
Energy Charge:									
First 3,650 kWhs	$0.11391	$0.00173	$0.11564	$0.00116	($0.00304)	$0.00293	$0.00010	$0.11679	$0.11507
All over 3,650 kWhs	$0.08370	$0.00173	$0.08543	$0.00085	($0.00304)	$0.00293	$0.00010	$0.08627	$0.08455
Demand Charge:									
20 kW or less	no charge		no charge	no charge					no charge
Over 20 kW	$6.00/kW		$6.00/kW					$6.00/kW	$6.00/kW
Large General Service - Schedule 21									
Energy Charge:									
First 250,000 kWhs	$0.07099	$0.00103	$0.07202	$0.00141	($0.00256)	$0.00247	$0.00008	$0.07342	$0.07240
All over 250,000 kWhs	$0.06349	$0.00103	$0.06452	$0.00126	($0.00256)	$0.00247	$0.00008	$0.06577	$0.06475
Demand Charge:									
50 kW or less	$450.00		$450.00	$50.00				$500.00	$500.00
Over 50 kW	$6.00/kW		$6.00/kW					$6.00/kW	$6.00/kW
Primary Voltage Discount	$0.20/kW		$0.20/kW					$0.20/kW	$0.20/kW
Extra Large General Service - Schedule 25									
Energy Charge:									
First 500,000 kWhs	$0.05708	$0.00042	$0.05750	($0.00092)	($0.00199)	$0.00180	$0.00005	$0.05644	$0.05616
500,000 - 6,000,000 kWhs	$0.05135	$0.00042	$0.05177	($0.00082)	($0.00199)	$0.00180	$0.00005	$0.05081	$0.05053
All over 6,000,000 kWhs	$0.04391	$0.00042	$0.04433	($0.00071)	($0.00199)	$0.00180	($0.00046)	$0.04297	$0.04320
Demand Charge:									
3,000 kva or less	$15,000		$15,000	$6,000				$21,000	$21,000
Over 3,000 kva	$5.25/kva		$5.25/kva	$0.75/kva				$6.00/kva	$6.00/kva
Primary Volt. Discount									
11 - 60 kv	$0.20/kW		$0.20/kW					$0.20/kW	$0.20/kW
60 - 115 kv	$1.10/kW		$1.10/kW					$1.10/kW	$1.10/kW
115 or higher kv	$1.40/kW		$1.40/kW					$1.40/kW	$1.40/kW
Annual Minimum	Present:	$779,230					Proposed:	$841,610	
Pumping Service - Schedule 31									
Basic Charge	$15.00		$15.00	$3.00				$18.00	$18.00
Energy Charge:									
First 165 kW/kWh	$0.09545	$0.00087	$0.09632	$0.00167	($0.00252)	$0.00222	$0.00007	$0.09776	$0.09712
All additional kWhs	$0.06817	$0.00087	$0.06904	$0.00119	($0.00252)	$0.00222	$0.00007	$0.07000	$0.06936

(1) Includes all present rate adjustments: Sch. 59 (BPA Residential Exchange), Sch. 91 (DSM Adjustment), Sch. 92 (LIRAP Adjustment), Sch. 93 (Energy Recovery Mechanism) and Sch 94 (BPA Transmission Revenue)

AVISTA UTILITIES
WASHINGTON ELECTRIC
ERM REVENUE DECREASE BY SERVICE SCHEDULE
(000s of Dollars)

Updated to reflect November 2014 Power Supply update & ERM offset.

			Present Base Revenue	ERM Offset	Percentage Change	kWh Rate	Billing Determinants
1	Residential	1	$214,476,179	$ (3,624,621)	-1.69%	$ (0.00149)	2,437,508,068
2	General Service	11/12	$69,492,932	$ (1,174,422)	-1.69%	$ (0.00200)	586,109,432
3	Large General Service	21/22	$127,830,953	$ (2,160,327)	-1.69%	$ (0.00150)	1,436,806,481
4	Extra Large General Service	25	$61,636,549	$ (1,041,650)	-1.69%	$ (0.00097)	1,076,126,636
5	Pumping Service	30/31/32	$10,524,650	$ (177,865)	-1.69%	$ (0.00139)	127,927,573
6	Street & Area Lights	41-48	$6,870,763	$ (116,115)	-1.69%	$ (0.00458)	25,328,044
7	Total		$490,832,026	$ (8,295,000)	-1.69%		5,689,806,234

REC Revenues Rebate Allocation - Generation Level Consumption

Line No.	DESCRIPTION A	TOTAL B	RESIDENTIAL SCHEDULE 1 C	GENERAL SVC. SCH. 11,12 D	LG. GEN. SVC. SCH. 21,22 E	EX LG GEN SVC SCHEDULE 25 F	PUMPING SCH. 30, 31, 32 H	ST & AREA LTG SCH. 41-48 I	J
1	**Generation Allocated**								
2	Total Generation Percentage	100.00%	42.51%	10.07%	25.68%	18.90%	2.38%	0.46%	(1)
3	2015 Rebate Amount	$ (5,936,379)	$ (2,535,008)	$ (609,554)	$ (1,523,015)	$ (1,097,649)	$ (144,558)	$ (26,594)	
4	Annual Load (Rate Year)	5,689,806,233	2,437,508,067	586,109,432	1,436,806,481	1,076,126,635	127,927,574	25,328,044	(2)
5	Cents Per kWh Rate		$ (0.00104)	$ (0.00104)	$ (0.00106)	$ (0.00102)	$ (0.00113)	$ (0.00105)	
6	Total Bills	2,922,458	2,494,197	369,788	24,074	253	34,146		
7	Avg Monthly Credit Per Customer		$ (1.02)	$ (1.65)	$ (63.26)	$ (4,338.53)	$ (4.23)		
8	Avg Annual Credit Per Customer		$ (12.20)	$ (19.78)	$ (759.17)	$ (52,062.41)	$ (50.80)		
9									
10	**Rate Calculation**								
11	18-mo Rebate Amt	$ (8,679,049)	$ (3,688,996)	$ (874,177)	$ (2,228,873)	$ (1,640,311)	$ (206,468)	$ (40,225)	
12	Load Forecast (18 Months)	8,347,293,891	3,563,388,464	836,891,898	2,109,870,302	1,615,235,840	183,456,283	38,451,104	
13	**Cents Per kWh Rate**		**$ (0.00104)**	**$ (0.00104)**	**$ (0.00106)**	**$ (0.00102)**	**$ (0.00113)**	**$ (0.00105)**	

(1) E02 Allocator (Generation Level Consumption)
(2) 2015 loads updated per Avista Response to Staff Data Request 24, Supplemental 2 Attachment A

Avista Electric
LIRAP Rate Calculation
UE-140188

			Settlement Billing Determinants *	Adjusted LIRAP Revenue	5.0% LIRAP Increase	Settlement LIRAP Revenue	Settlement Sch 92 kWh Rate
1	Residential	1	2,437,508,067	$ 1,790,246	$ 89,512	$ 1,879,759	$ 0.00077
2	General Service	11/12	586,109,432	$ 621,110	$ 31,055	$ 652,166	$ 0.00111
3	Large General Service	21/22	1,436,806,481	$ 1,115,575	$ 55,779	$ 1,171,354	$ 0.00082
4	Extra Large General Service	25	668,283,785	$ 322,543	$ 16,127	$ 338,670	$ 0.00051
5	Pumping Service	30/31/32	127,927,574	$ 85,904	$ 4,295	$ 90,199	$ 0.00071
6	Street & Area Lights	41-48	25,328,044	$ 63,439	$ 3,172	$ 66,611	0.96%
7	Total		5,281,963,383	$ 3,998,818	$ 199,940	$ 4,198,758	

* The 3rd block billing determinants of Schedule 25 excluded per Settlement Agreement.

AVISTA UTILITIES
WASHINGTON NATURAL GAS
PROPOSED INCREASE BY SERVICE SCHEDULE
12 MONTHS ENDED DECEMBER 31, 2015
(000s of Dollars)

Line No.	Type of Service	Schedule Number	Base Tariff Revenue Under Present Rates(1)	Proposed General Increase	Base Tariff Revenue Under Proposed Rates	**Base Tariff Percent Increase**	Total Billed Revenue at Present Rates (2)	Sch. 192 LIRAP Increase	Total GRC/LIRAP Increase	**Percent Increase on Billed Revenue (2)**
	(a)	(b)	(c)	(d)	(e)	**(f)**	(g)	(h)	(i)	**(j)**
1	General Service	101	$110,008	$6,581	$116,589	**6.0%**	$114,458	$156	$6,737	**5.9%**
2	Large General Service	111/112	$34,391	$1,515	$35,906	**4.4%**	$35,967	$51	$1,566	**4.4%**
3	Large General Svc.-High Annual Load Factor	121/122	$3,932	$181	$4,113	**4.6%**	$4,181	$6	$187	**4.5%**
4	Interruptible Service	131/132	$768	$43	$811	**5.6%**	$798	$1	$44	**5.5%**
5	Transportation Service	146	$2,434	$180	$2,614	**7.4%**	$2,436	$0	$180	**7.4%**
6	Special Contracts	148	$1,542	$0	$1,542	**0.0%**	$1,542	$0	$0	**0.0%**
7	Total		$153,075	$8,500	$161,575	**5.6%**	$159,383	$214	$8,716	**5.5%**

* All revenue based on 2015 billing determinants

(1) Includes Purchase Adjustment Schedule 150; excludes all other rate adjustments.

(2) Includes Schedule 150 (Purchase Gas Cost Adjustment), Schedule 155 (Gas Rate Adjustment), Schedule 159 (Decoupling), Schedule 191 (DSM), and Schedule 192 (LIRAP).

AVISTA UTILITIES
WASHINGTON NATURAL GAS
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

Type of Service (a)	Base Rate (b)	Sch. 150 PGA Rate Adj (c)	Base Rate Including Schedule 150 (d)	Present Billing Rate Adj. (e)	Present Billing Rate (1) (f)	General Rate Increase (g)	Sch. 192 LIRAP Increase (h)	Proposed Billing Rate(1) (i)	Proposed Base Rate Including Schedule 150 (j)	Proposed Base Rate excluding Schedule 150 (k)
General Service - Schedule 101										
Basic Charge			$8.00		$8.00	$1.00		$9.00	$9.00	$9.00
Usage Charge:										
First 70 Therms	0.28219	0.49803	$0.78022	$0.03803	$0.81825	$0.03901	$0.00133	$0.85859	$0.81923	$0.32120
All over 70 Therms	0.38327	0.49803	$0.88130	$0.03803	$0.91933	$0.04406	$0.00133	$0.96472	$0.92536	$0.42733
Large General Service - Schedule 111										
Usage Charge:										
First 200 therms	0.39131	0.49535	$0.88666	$0.03407	$0.92073	$0.04389	$0.00111	$0.96573	$0.93055	$0.43520
200 - 1,000 therms	0.26644	0.49535	$0.76179	$0.03407	$0.79586	$0.03735	$0.00111	$0.83432	$0.79914	$0.30379
All over 1,000 therms	0.19322	0.49535	$0.68857	$0.03407	$0.72264	$0.03376	$0.00111	$0.75751	$0.72233	$0.22698
Minimum Charge:										
per month			$161.21		$161.21	($74.17)		$87.04	$87.04	$87.04
per therm	-0.41474	0.49535	$0.08061	$0.03407	$0.11468	$0.41474		$0.52942	$0.49535	$0.00000
High Annual Load Factor Large General Service - Schedule 121										
Usage Charge:										
First 500 therms	0.40597	0.47449	$0.88046	$0.04203	$0.92249	$0.02451	$0.00102	$0.94802	$0.90497	$0.43048
500 - 1,000 therms	0.28246	0.47449	$0.75695	$0.04203	$0.79898	$0.03980	$0.00102	$0.83980	$0.79675	$0.32226
1,000 - 10,000 therms	0.20758	0.47449	$0.68207	$0.04203	$0.72410	$0.03586	$0.00102	$0.76098	$0.71793	$0.24344
10,000 - 25,000 therms	0.16056	0.47449	$0.63505	$0.04203	$0.67708	$0.03339	$0.00102	$0.71149	$0.66844	$0.19395
All over 25,000 therms	0.12272	0.47449	$0.59721	$0.04203	$0.63924		$0.00102	$0.64026	$0.59721	$0.12272
Minimum Charge:										
per month			$409.92		$409.92	($194.68)		$215.24	$215.24	$215.24
per therm	-0.41387	0.47449	$0.06062	$0.04203	$0.10265	$0.41387	$0.00102	$0.51754	$0.47449	$0.00000
Annual Minimum per therm			Present:	$0.30041				Proposed:	$0.33816	$0.33816
Interruptible Service - Schedule 132										
Usage Charge:										
First 10,000 therms	0.18974	0.44955	$0.63929	$0.02359	$0.66288	$0.03580	$0.00098	$0.69966	$0.67509	$0.22554
10,000 - 25,000 therms	0.1447	0.44955	$0.59425	$0.02359	$0.61784	$0.03328	$0.00098	$0.65210	$0.62753	$0.17798
25,000 - 50,000 therms	0.13365	0.44955	$0.58320	$0.02359	$0.60679	$0.03266	$0.00098	$0.64043	$0.61586	$0.16631
All over 50,000 therms	0.12999	0.44955	$0.57954	$0.02359	$0.60313	$0.03245	$0.00098	$0.63656	$0.61199	$0.16244
Annual Minimum per therm			Present:	$0.21578				Proposed:	$0.24776	$0.24776
Transportation Service - Schedule 146										
Basic Charge			$400.00		$400.00	$100.00		$500.00	$500.00	$500.00
Usage Charge:										
First 20,000 therms	0.08233	0.00056	$0.08289	$0.00004	$0.08293	$0.00482		$0.08775	$0.08771	$0.08715
20,000 - 50,000 therms	0.07324	0.00056	$0.07380	$0.00004	$0.07384	$0.00429		$0.07813	$0.07809	$0.07753
50,000 - 300,000 therms	0.06603	0.00056	$0.06659	$0.00004	$0.06663	$0.00387		$0.07050	$0.07046	$0.06990
300,000 - 500,000 therms	0.06106	0.00056	$0.06162	$0.00004	$0.06166	$0.00358		$0.06524	$0.06520	$0.06464
All over 500,000 therms	0.04586	0.00056	$0.04642	$0.00004	$0.04646	$0.00270		$0.04916	$0.04912	$0.04856
Annual Minimum per therm			Present:	$0.07380				Proposed:	$0.07809	$0.07809

(1) Includes Schedule 150 (Purchase Gas Cost Adjustment), Schedule 155 (Gas Rate Adjustment), Schedule 191 (DSM Adjustment), and Schedule 192 (LIRAP Adjustment).

Avista Natural Gas
LIRAP Rate Calculation
UG-140189

		Billing Determinants	Present LIRAP Revenue	11.6% LIRAP Increase	Settlement LIRAP Revenue	Settlement Sch 192 Therm Rate
General Service	101	117,011,207	$ 1,339,778	$ 155,414	$ 1,495,193	$ 0.01278
Large General Service	111/112	46,256,893	$ 444,066	$ 51,512	$ 495,578	$ 0.01071
Large General Svc.-High Annual Load Factor	121/122	5,940,558	$ 52,039	$ 6,037	$ 58,076	$ 0.00978
Interruptible Service	131/132	1,288,220	$ 10,847	$ 1,258	$ 12,105	$ 0.00940
Transportation Service	146	31,023,878	$ -	$ -	$ -	$ -
Special Contracts	148	46,142,216	$ -	$ -	$ -	$ -
Total		247,662,972	$ 1,846,731	$ 214,221	$ 2,060,951	

SECOND REVISED APPENDIX 3

Updated November 2014

Avista Corp
Pro forma January 2015 - December 2015
ERM Authorized Expense and Retail Sales
Adjusted to Reflect 2015 System Loads (1)

Reflects November Power Supply update.

ERM Authorized Power Supply Expense - System Numbers (2)

	Total	January	February	March	April	May	June	July	August	September	October	November	December
Account 555 - Purchased Power	$129,676,714	$14,241,308	$12,816,216	$12,684,102	$10,157,992	$8,801,839	$8,966,511	$9,032,312	$10,449,135	$8,227,612	$8,950,494	$12,731,418	$12,617,776
Account 501 - Thermal Fuel	$28,629,127	$2,663,532	$2,484,671	$2,578,707	$2,068,252	$1,665,745	$1,511,381	$2,254,578	$2,621,357	$2,672,936	$2,757,933	$2,649,850	$2,700,185
Account 547 - Natural Gas Fuel	$89,764,664	$10,133,311	$9,419,650	$9,305,476	$5,867,735	$3,112,735	$2,595,918	$5,623,100	$7,743,935	$8,219,145	$8,834,779	$9,035,104	$9,873,776
Account 447 - Sale for Resale	$75,430,452	$5,385,864	$7,026,454	$8,167,295	$8,655,099	$9,111,902	$8,389,009	$5,130,621	$3,284,320	$4,661,364	$4,875,558	$6,000,154	$4,742,812
Power Supply Expense (3)	$172,640,053	$21,652,287	$17,694,083	$16,400,990	$9,438,880	$4,468,417	$4,684,802	$11,779,369	$17,530,106	$14,458,328	$15,667,649	$18,416,218	$20,448,924
Transmission Expense	$16,817,737	$1,447,542	$1,429,504	$1,405,324	$1,394,208	$1,365,074	$1,353,383	$1,377,511	$1,429,273	$1,414,185	$1,374,889	$1,403,813	$1,423,031
Transmission Revenue	$16,015,349	$1,304,329	$1,105,921	$1,123,977	$1,154,782	$1,377,232	$1,552,357	$1,659,835	$1,502,892	$1,306,364	$1,460,291	$1,241,936	$1,225,427
Broker Fees	$1,076,000	$89,667	$89,667	$89,667	$89,667	$89,667	$89,667	$89,667	$89,667	$89,667	$89,667	$89,667	$89,667
Total (5)	$174,518,441	$21,885,166	$18,107,332	$16,772,004	$9,767,972	$4,545,924	$4,575,493	$11,586,711	$17,546,153	$14,655,815	$15,671,913	$18,667,761	$20,736,195

ERM Authorized Power Supply Expense - 100% Washington Allocation

	Total	January	February	March	April	May	June	July	August	September	October	November	December
Washington EIA REC Purchase	$725,000	$181,250			$181,250			$181,250			$181,250		

ERM Authorized Washington Retail Sales

	Total	January	February	March	April	May	June	July	August	September	October	November	December
2015 Total Retail Sales, MWh (4)	5,689,806	545,205	498,034	487,551	422,246	421,982	420,901	464,392	489,763	426,967	452,424	490,319	570,023
Retail Revenue Credit Rate	$20.12 /MWh												

(1) The November 2014 power supply update is based on 2015 system loads.
(2) Multiply system numbers by 65.19% to determine Washington share.
(3) Power Supply Expense has been adjusted to reflect 2015 system loads.
(4) Reflects 2015 billing determinants used to set rates.
(5) The November 2014 update of net power supply costs will be compared to the Total of $167,877,570 to determine the increase or decrease to the $7.0 million base revenue increase effective Janaury 1, 2015. The November 2014 updated net power supply costs have been reduced by $500,000 (System) Staff adjustment, and increased by the $725,000 (Washington share) REC expenses excluded from the REC rebate calculation.

	System	WA Share
Power Cost Total in Stipulation	$167,877,570	$109,439,388
Updated System Power Cost	$174,518,441	$113,768,572
Direct WA EIA REC Purchase		$725,000
Total Updated WA Power Cost		$114,493,572
Change in WA Power Cost		$5,054,184
FIT		$1,768,964
NOI Requirement		$3,285,220
Conversion Factor		0.62049
Power Supply Update Revenue Requirement		$\boxed{\$5,294,557}$

SECOND REVISED APPENDIX 4

Updated November 2014

Avista Utilities
Electric Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Electric

Updated to reflect November 2014 Power Supply update.

		TOTAL	RESIDENTIAL SCHEDULE 1	GENERAL SVC. SCH. 11,12	LG. GEN. SVC. SCH. 21,22	PUMPING SCH. 30, 31, 32	EX LG GEN SVC SCHEDULE 25	ST & AREA LTG SCH. 41-48
1	Total Normalized 2015 Revenue (Appendix 2)	$ 490,833,000	$ 214,476,000	$ 69,493,000	$ 127,831,000	$ 10,525,000	$ 61,637,000	$ 6,871,000
2	Settlement Revenue Increase (Appendix 2)	$ 12,295,000	$ 5,372,000	$ 1,738,000	$ 3,205,000	$ 264,000	$ 1,544,000	$ 172,000
3	Total Rate Revenue (January 1, 2015)	$ 503,128,000	$ 219,848,000	$ 71,231,000	$ 131,036,000	$ 10,789,000	$ 63,181,000	$ 7,043,000
4	Normalized kWhs (2015 Rate Year)	5,689,806,234	2,437,508,068	586,109,432	1,436,806,481	127,927,573	1,076,126,636	25,328,044
5	Retail Revenue Credit (line 14)	$ 0.02108	$ 0.02108	$ 0.02108	$ 0.02108	$ 0.02108	$ 0.02108	$ 0.02108
6	Variable Power Supply Revenue (L4 * L5)	$ 119,941,115	$ 51,382,670	$ 12,355,187	$ 30,287,881	$ 2,696,713	$ 22,684,749	$ 533,915
7	Delivery & Power Plant Revenue (L3 - L6)	$ 336,181,549	$ 168,465,330	$ 58,875,813	$ 100,748,119	$ 8,092,287		
8	Customer Bills (2015 Rate Year)	2,917,521	2,494,197	369,788	24,074	29,462		
9	Proposed Basic Charges		$ 8.50	$ 18.00	$ 500.00	$ 18.00		
10	Basic Charge Revenue (Ln 8 * Ln 9)	$ 40,424,175	$ 21,200,675	$ 6,656,184	$ 12,037,000	$ 530,316		
11	Decoupled Revenue	$ 295,757,375	$ 147,264,655	$ 52,219,629	$ 88,711,119	$ 7,561,971	Excluded From Decoupling	
12	Retail Revenue Credit - (Appendix 3)	$0.02012						
13	Gross Up Factor for Revenue Related Exp	104.76%						
14	Grossed Up Retail Revenue Credit	$0.02108						

		Residential	Non-Residential Group
15	Average Number of Customers (Line 8 / 12)	207,850	35,277
16	Annual kWh	2,437,508,068	2,150,843,486
17	Basic Charge Revenues	21,200,675	19,223,500
18	Customer Bills	2,494,197	423,324
19	Average Basic Charge	$8.50	$45.41

Updated to reflect November 2014 Power Supply update.

Avista Utilities
Electric Decoupling Mechanism
Development of Annual Decoupled Revenue Per Customer - Electric

Line No.		Source		Residential		Non-Residential Schedules*
	(a)	(b)		(c)		(d)
1	Decoupled Revenues	Appendix 4, Page 1	$	147,264,655	$	148,492,719
2	Rate Year # of Customers 2015	Revenue Data		207,850		35,277
3	Decoupled Revenue per Customer	(1) / (2)	$	708.51	$	4,209.34

* Schedules 11, 12, 21, 22, 31, 32.

Avista Utilities
Electric Decoupling Mechanism
Development of Monthly Decoupled Revenue Per Customer - Electric

Updated to reflect November 2014
Power Supply update.

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**Electric Sales**														
2	*Residential*														
3	- Weather-Normalized kWh Sales	Monthly Rate Year	271,130,047	240,621,765	221,370,825	175,525,307	161,914,993	154,545,588	176,072,045	186,627,300	157,769,890	180,730,371	225,437,958	285,761,978	2,437,508,067
4	- % of Annual Total	% of Total	11.12%	9.87%	9.08%	7.20%	6.64%	6.34%	7.22%	7.66%	6.47%	7.41%	9.25%	11.72%	100.00%
5	*Non-Residential**														
6	- Weather-Normalized kWh Sales	Monthly Rate Year	181,922,081	170,861,843	173,030,139	157,004,730	167,947,307	175,614,812	195,632,184	207,327,409	177,370,453	177,453,044	174,351,964	192,327,521	2,150,843,487
7	- % of Annual Total	% of Total	8.46%	7.94%	8.04%	7.30%	7.81%	8.16%	9.10%	9.64%	8.25%	8.25%	8.11%	8.94%	100.00%
8	**Monthly Decoupled Revenue Per Customer ("RPC")**														
9	*Residential*														
10	- 2015 Decoupled RPC	Appendix 4, P. 2 L. 3													$ 708.51
11	- 2015 Monthly Decoupled RPC	(4) x (10)	$ 78.81	$ 69.94	$ 64.35	$ 51.02	$ 47.06	$ 44.92	$ 51.18	$ 54.25	$ 45.86	$ 52.53	$ 65.53	$ 83.06	$ 708.51
12	*Non-Residential**														
13	- 2015 Decoupled RPC	Appendix 4, P. 2 L. 3													$ 4,209.34
14	- 2015 Monthly Decoupled RPC	(7) x (13)	$ 356.03	$ 334.39	$ 338.63	$ 307.27	$ 328.68	$ 343.69	$ 382.86	$ 405.75	$ 347.13	$ 347.29	$ 341.22	$ 376.40	$ 4,209.34

* Schedules 11, 12, 21, 22, 31, 32.

APPENDIX 5

Avista Utilities
Natural Gas Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Natural Gas

	TOTAL	RESIDENTIAL SCHEDULE 101	GENERAL SVC. SCH. 111	LG. GEN. SVC. SCH. 121	INTERRUPTIBLE SCH 131	SCHEDULES 112, 122, 132	SCHEDULES 146 & 148
1 Total Normalized 2015 Revenue (Appendix 2)	$ 153,075,000	$ 110,008,000	$ 34,391,000	$ 3,645,000	$ -	$ 1,055,000	$ 3,976,000
2 Settlement Revenue Increase (Appendix 2)	$ 8,500,000	$ 6,581,000	$ 1,515,000	$ 168,000	$ -	$ 56,000	$ 180,000
3 Total Rate Revenue (January 1, 2015)	$ 161,575,000	$ 116,589,000	$ 35,906,000	$ 3,813,000	$ -	$ 1,111,000	$ 4,156,000
4 Normalized Therms (2015 Rate Year)	247,662,972	117,011,207	46,256,893	5,507,204	-	1,721,574	77,166,094
5 PGA Rates		$ 0.49803	$ 0.49535	$ 0.47449	$ 0.44955		
6 Variable Gas Supply Revenue	$ 83,801,557	$ 58,275,091	$ 22,913,352	$ 2,613,113	$ -		
7 Delivery Revenue (Ln 3 - Ln 6)	$ 72,506,443	$ 58,313,909	$ 12,992,648	$ 1,199,887	$ -		
8 Customer Bills (2015 Rate Year)	1,833,425	1,802,235	30,276	305	0	48	561
9 Settlement Basic Charges		$9.00	$87.04	$215.24	$0.00		
10 Basic Charge Revenue (Ln 8 * Ln 9)	$ 18,920,986	$ 16,220,115	$ 2,635,223	$ 65,648	$ -		
11 Decoupled Revenue	$ 53,585,457	$ 42,093,794	$ 10,357,425	$ 1,134,239	$ -	Excluded From Decoupling	

	Residential	Non-Residential Group
12 Average Number of Customers (Line 8 / 12)	150,186	2,548
13 Annual Therms	117,011,207	51,764,097
14 Basic Charge Revenues	$ 16,220,115	$ 2,700,871
15 Customer Bills	1,802,235	30,581
16 Average Basic Charge	$9.00	$88.32

Avista Utilities
Natural Gas Decoupling Mechanism
Development of Decoupled Revenue Per Customer - Natural Gas

Line No.		Source	Residential	Non-Residential Schedules*
	(a)	(b)	(c)	(d)
1	Decoupled Revenues	Appendix 5, Page 1	$ 42,093,794	$ 11,491,664
2	Rate Year # of Customers 2015	Revenue Data	150,186	2,548
3	Decoupled Revenue Per Customer	(1) / (2)	$ 280.28	$ 4,509.33

*Sales Schedules 111, 121, 131.

Avista Utilities
Natural Gas Decoupling Mechanism
'Development of Monthly Decoupled Revenue Per Customer - Natural Gas

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1															
2	**Natural Gas Delivery Volume**														
3	*Residential*														
4	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	20,096,515	16,729,826	14,285,474	9,202,394	5,127,082	3,376,941	2,456,171	2,227,453	2,907,962	6,931,034	13,836,643	19,833,713	117,011,207
5	- % of Annual Total	% of Total	17.17%	14.30%	12.21%	7.86%	4.38%	2.89%	2.10%	1.90%	2.49%	5.92%	11.83%	16.95%	100.00%
6															
7	*Non-Residential Sales**														
8	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	7,372,432	6,284,928	5,638,128	3,840,835	2,388,634	1,911,614	1,631,753	1,792,654	2,433,461	4,483,160	6,399,826	7,586,671	51,764,097
9	- % of Annual Total	% of Total	14.24%	12.14%	10.89%	7.42%	4.61%	3.69%	3.15%	3.46%	4.70%	8.66%	12.36%	14.66%	100.00%
10															
11	**Monthly Decoupled Revenue Per Customer ("RPC")**														
12	*Residential*														
13	- 2015 Decoupled RPC	Appendix 5, P. 2 L. 3													$ 280.28
14	- 2015 Monthly Decoupled RPC	(5) x (13)	$ 48.14	$ 40.07	$ 34.22	$ 22.04	$ 12.28	$ 8.09	$ 5.88	$ 5.34	$ 6.97	$ 16.60	$ 33.14	$ 47.51	$ 280.28
15															
16	*Non-Residential Sales**														
17	- 2015 Decoupled RPC	Appendix 5, P. 2 L. 3													$ 4,509.33
18	- 2015 Monthly Decoupled RPC	(9) x (17)	$ 642.24	$ 547.50	$ 491.15	$ 334.59	$ 208.08	$ 166.53	$ 142.15	$ 156.16	$ 211.99	$ 390.54	$ 557.51	$ 660.90	$ 4,509.33
19															
20	*Sales Schedules 111, 121, 131.														

Service Date: March 25, 2020

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. AVISTA CORPORATION, d/b/a AVISTA UTILITIES, Respondent.	DOCKETS UE-190334, UG-190335, and UE-190222 *(Consolidated)* FINAL ORDER 09 REJECTING TARIFF SHEETS; APPROVING AND ADOPTING PARTIAL MULTIPARTY SETTLEMENT STIPULATION; RESOLVING CONTESTED ISSUES; AUTHORIZING AND REQUIRING COMPLIANCE FILING

Synopsis: *The Commission approves and adopts a partial multiparty settlement stipulation (Settlement) that proposes to resolve multiple contested issues and is agreed by all parties, with the exception that Public Counsel opposes the portion of the Settlement regarding natural gas revenue requirement. The Settlement establishes new revenue requirements for both Avista's electric and natural gas services, updates Avista's cost of capital, addresses rate spread and rate design for Avista's electric and natural gas services, resolves how the final Energy Recovery Mechanism (ERM) deferred balance will be returned to customers, addresses depreciation and decommissioning and remediation costs for the Colstrip power plant in Rosebud County, Montana, places limitations on capital investments in the Colstrip plant, addresses Colstrip-related transmission planning, grants funding for Colstrip community transition, increases low-income weatherization and LIRAP funding, addresses deferral amortizations for the Fee Free and LEAP programs, and resolves several programmatic and contractual issues. The parties agree to, and the Commission approves in this Order, an overall electric revenue increase of $28.5 million (5.4 percent billed increase). Apart from Public Counsel, the parties agree to an overall natural gas revenue increase of $8.0 million (5.2 percent billed increase), which the Commission approves.*

The Commission also resolves a number of fully contested issues related to decoupling, and several non-Colstrip ERM issues including bias in net power costs calculations and authorized gas transport revenues, the ongoing stakeholder workshop process regarding power costs, the carrying charge on the ERM deferral balance, and deferral amounts related to baseline power costs from the remanded Avista 2015 general rate case in consolidated Dockets UE-150204 and UG-150205

The Commission authorizes Avista's decoupling mechanisms to continue until March 31, 2025, subject to the requirement that a qualified third-party evaluate the mechanisms' performance after the third year. In so doing, the Commission rejects Public Counsel's proposal to replace the mechanisms with a lost revenue adjustment mechanism or, in the alternative, a rate class decoupling mechanism.

The Commission determines that certain modifications to Avista's decoupling mechanisms are appropriate and in the public interest. The Commission approves Avista's proposal to remove new customers from the decoupling mechanisms and requires that the third-party evaluator include in its analysis an evaluation of this design component. Additionally, the Commission approves Avista's commitment to achieve an additional 5 percent of its conservation targets for both electric and natural gas, and rejects NWEC's alternative proposal. We also approve moving the effective date of Avista's annual decoupling tariff revisions from November 1 to August 1, finding that this will simultaneously aid Avista in recovering revenues within two years of the deferral period and also aid ratepayers by avoiding multiple rate changes within a short time because the decoupling tariff revisions will now align with Avista's annual demand side management rate filings. Last, we reject the proposal to adopt a 20-year moving average of weather data for Avista's decoupling mechanisms at this juncture but determine that the Commission should engage in a broader conversation with stakeholders about the value of moving towards using more recent periods of weather data. To aid in this discussion and to better understand how weather variability affects Avista's decoupling mechanisms, we require Avista to maintain and present data for 30-, 20-, 15-, and 10-year moving averages, and that this design element and data be analyzed by the third-party evaluator.

In Avista's previous rate case, Dockets UE-170485, UG-170486, UE-171221, and UG-171222 (Consolidated)*, we found bias in the power cost calculations and instructed Avista and stakeholders to collaborate in a workshop setting to resolve these concerns. We decline Public Counsel's request to reiterate our previous finding. Instead, we continue to support and encourage the workshop process.*

We approve Avista's uncontested calculation of the carrying charge for its ERM. Additionally, we find that the remand deferral amounts related to baseline power costs are not within the scope of this proceeding, but are resolved in Dockets UE-150204 and UG-150205 (Consolidated) *by Order 11.*

In Order 11 of the remand proceeding, we indicated that we would resolve how refunds from that remanded case must be distributed to customers. Here, we determine that Avista must return $4,919,000 to electric customers and $3,571,000 to natural gas customers over the course of one year to address the public interest need created by the circumstances of the ongoing COVID-19 pandemic and through a separate tariff to allow for tracking and transparency.

Lastly, due to the 2018 Colstrip outage, Avista incurred an additional $3,274,000 in replacement power costs and failed to prove that these costs were prudently incurred. The Commission determined in Order 05 of Docket UE-190882 that this amount, approximately $3.3 million, cannot be recovered from Avista's Washington ratepayers. According to the Settlement's terms, the total ERM deferral balance is calculated by incorporating this approximately $3.3 million with the estimated balance of approximately $35.8 million and is returned to ratepayers over two years. The Settlement does not prescribe an apportionment of the ERM deferral balance over these two years. Under the current circumstances facing Avista ratepayers resulting from the COVID-19 pandemic, we determine that Avista must return a greater portion of the ERM deferral balance in the first year to achieve a net zero impact, in concert with the other rate decisions we make in this Order, to Avista's electric revenue requirement beginning April 1, 2020.

The Commission determines that approval of the Settlement, without condition, in concert with the other decisions we make in this Order, establish rates, terms, and conditions for Avista's electric and natural gas services that are fair, just, reasonable, and sufficient. The Commission, therefore, rejects the tariff sheets filed by Avista on March 31, 2019, and April 30, 2019, including the Company's proposed multi-year rate plan. The Commission, considering the full record, authorizes and requires Avista to file tariff sheets that comply with the terms of the Settlement and this Order.

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BACKGROUND

1 This case concerns the 2019 electric and natural gas general rate case filing and Energy Recovery Mechanism (ERM) adjustment filing of Avista Corporation, d/b/a Avista Utilities (Avista or Company).

A. PROCEDURAL HISTORY

2 On March 29, 2019, Avista filed with the Washington Utilities and Transportation Commission (Commission) tariff revisions designed to rebate to customers approximately $34.4 million through Avista's ERM in Docket UE-190222. This filing was made pursuant to the Multiparty Settlement Stipulation in Docket UE-120436, subsection 10, related to the ERM rate adjustment trigger, and in accordance with Docket UE-011595, which requires Avista to file annual testimony and supporting work papers on or before April 1 of each year.

3 On April 30, 2019, Avista filed a general rate case (GRC) with the Commission containing revisions to its currently effective Tariff WN U-28, Electric Service, in Docket UE-190334 and revisions to its currently effective Tariff WN U-29, Natural Gas, in Docket UG-190335 (GRC Dockets). Avista's filing proposed a two-year rate plan. For the first year of the rate plan, Avista proposed an increase in electric revenues of $45.8 million, or 8.8 percent on a billed revenue basis, and an increase in natural gas revenues of $12.9 million, or 10.1 percent on a billed revenue basis. For the second year of the rate plan, Avista proposed an increase in electric revenues of $18.9 million, or 3.3 percent on a billed revenue basis, and an increase in natural gas revenues of $6.5 million, or 4.6 percent on a billed revenue basis.

4 On May 8, 2019, the Commission issued Order 01, Complaint and Order Suspending Tariff Revisions and Order of Consolidation (Order 01), consolidating the electric and natural gas rate case filings (Dockets UE-190334 and UG-190335), suspending the tariffs, and setting the matters for adjudication. On May 9, 2019, the Commission issued Order 02, Protective Order, in Dockets UE-190334 and UG-190335.

5 The Commission convened a prehearing conference at Olympia, Washington on May 24, 2019, before Administrative Law Judge Andrew J. O'Connell.

6 On May 30, 2019, the Commission issued Order 03, Order of Consolidation, Suspension, Notice Extending Time to Intervene, Prehearing Conference Order, Notice of Hearing (Order 03), consolidating Avista's ERM in Docket UE-190222 with the GRC Dockets.

By Order 03, the Commission adopted an agreed procedural schedule presented by the parties at the Prehearing Conference and set a hearing for the consolidated dockets beginning on December 11, 2019. Order 03 also granted intervention in all proceedings to the Alliance of Western Energy Consumers (AWEC), The Energy Project, Sierra Club, and NW Energy Coalition (NWEC) (collectively with Avista, Commission Staff, and Public Counsel, "the Parties"). That same day, the Commission modified Order 02 to incorporate the consolidation of Docket UE-190222.

7 On September 26, 2019, Staff filed a motion requesting to suspend the filings in Puget Sound Energy's (PSE) 2019 Power Cost Adjustment (PCA) in Docket UE-190324, and Pacific Power & Light Company's (Pacific Power) 2019 Power Cost Adjustment Mechanism (PCAM) in Docket UE-190458. Staff's motion also requested that the Commission sever Avista's ERM filing, Docket UE-190222, from the GRC Dockets and consolidate it with Dockets UE-190324 and UE-190458. Staff also moved to suspend the October 3, 2019, testimony filing deadline in Docket UE-190222.

8 On October 2, 2019, the Commission granted the portion of Staff's motion requesting suspension of the October 3, 2019, testimony filing deadline in Docket UE-190222.[1]

9 On October 24, 2019, the Commission issued Order 06 in these dockets, Denying Motion to Sever and Consolidate, Initiating Investigation, Modifying Procedural Schedule, Setting Procedural Schedule (Order 06). By Order 06, the Commission denied the remaining portions of Staff's motion, but initiated an investigation in Docket UE-190882 into the limited issue of the prudency of decision making leading up to the 2018 Colstrip outage and the costs incurred to acquire replacement power.[2] The Commission exercised its authority and discretion to move the portions of Dockets UE-190222, UE-190324, and UE-190458 related to that limited issue to Docket UE-190882.[3] The determination reached in Docket UE-190882 is binding in Docket UE-190222.[4] The Commission also

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[1] The Commission issued "Order 04 Suspending Filing Deadline in Docket UE-190222; Requiring Non-Company Parties to File Contested Issues Lists in Docket UE-190222." The caption of the order was later corrected to entitle it as "Order 05." *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-190334, UG-190335, UE-190222 *(Consolidated)*, Order 05 (Oct. 23, 2019).

[2] *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-190334, UG-190335, UE-190222 *(Consolidated)*, Order 06, 7, ¶ 23 (Oct. 23, 2019) [hereinafter Order 06].

[3] *Id.* at 7, ¶ 25.

[4] *Id.* at 8, ¶ 27.

established a new procedural schedule for Dockets UE-190334, UG-190335, and UE-190222 *(Consolidated)*, which made accommodations for filing testimony that was suspended by the Commission on October 2, 2019, set a new deadline of December 13, 2019, for rebuttal and cross-answer testimony, and scheduled a new evidentiary hearing date of January 8, 2020, to hear the remaining issues in Docket UE-190222.[5]

10 The Commission held a public comment hearing in Spokane, Washington, on October 28, 2019. Over the course of the GRC proceeding, including the public comment hearing, the Commission and Public Counsel received 146 total public comments from Washington customers regarding the proposed rate increases; 141 comments opposed the increases, no comments supported the increases, and five comments took no position.[6] Most comments addressed customer concerns about their ability to pay bills due to low-income and fixed-income issues, and many expressed a desire for less frequent rate increases. Other customers were concerned about energy efficiency, the costs of continuing coal-generated electricity, Avista's recent stock valuation, and the failed merger with HydroOne.

11 On October 29, 2019, the Commission issued Order 07, Supplemental Protective Order (Order 07). The Commission accepted a proposal by the Parties to these consolidated dockets and Dockets UE-190324 and UE-190458 to issue a two-tiered protective order with multiple confidentiality designations – a traditional "confidential information" designation and a special "company-confidential information" designation. Order 07 implemented these protections and, in conjunction with the protective order in Docket UE-190882, afforded the Parties in these consolidated dockets the ability to gather and use information across these dockets.[7]

12 On November 7, 2019, Avista filed a motion to modify the procedural schedule in these consolidated dockets to accommodate a partial settlement reached by the Parties. Avista represented that the settlement in principle included all matters in dispute except for

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[5] *Id.* at 6-7, ¶¶ 21-22, Appendix A.

[6] Public Comments, Exh. BR-2.

[7] *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-190334, UG-190335, UE-190222 *(Consolidated)*, Order 07, 1-2, ¶ 4 (Oct. 29, 2019). *See also in re the Investigation of Avista Corp. d/b/a Avista Utils., Puget Sound Energy, and Pacific Power & Light Co. Regarding Prudency of Outage and Replacement Power Costs*, Docket UE-190882, Order 02, 5-6, ¶¶ 15-16 (Oct. 28, 2019).

decoupling and the remaining issues related to Avista's ERM that were not moved to Docket UE-190882.

13 On November 8, 2019, the Commission issued Order 08, Granting Motion to Modify Procedural Schedule, Notice of Evidentiary and Settlement Hearing (set for Wednesday, December 11, 2019, at 9:30 a.m.) (Order 08). By Order 08, the Commission adopted a November 21, 2019, deadline for the Parties to file the partial settlement, and a November 26, 2019, deadline to file testimony in support of the partial settlement.

14 On November 21, 2019, the Parties filed a partial multiparty settlement agreement (Settlement). Public Counsel joins the settlement, in part, but opposes the portion related to the Company's natural gas revenue requirement.

15 On November 21, 2019, Avista, Staff, and NWEC filed with the Commission rebuttal and cross-answering testimony, respectively, to address the remaining contested issues in the GRC Dockets. Public Counsel submitted a letter in the docket indicating that it did not intend to file cross-answering testimony.

16 On November 25, 2019, the Commission issued a Notice Revising Procedural Schedule and Notice of Hearing (beginning January 21, 2020, at 10 a.m.). The November 25, 2019, Notice cancelled the December 11, 2019, and January 8, 2020, hearing dates and established agreed revisions to the procedural schedule, which set a hearing on January 21, 2020, to address all issues in these consolidated dockets, a deadline of December 9, 2019, for filing testimony and exhibits opposing the Settlement, and a deadline of December 23, 2019, for filing testimony and exhibits responding to the testimony opposing the Settlement.

17 On November 26, 2019, the Parties filed with the Commission Joint Testimony in Support of the Partial Multiparty Settlement Stipulation (Settlement).[8]

18 On December 9, 2019, Public Counsel filed testimony and exhibits opposing the portion of the Settlement related to the natural gas revenue requirement.

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[8] The parties' testimony supporting the Settlement maintained Public Counsel's position opposing the portion of the Settlement regarding Avista's natural gas revenue requirement. *See* Ehrbar *et. al.*, Exh. JT-1 at 1:21-27.

19 On December 13, 2019, Avista filed rebuttal testimony and exhibits in Docket UE-190222 regarding ERM issues not designated for resolution in Docket UE-190882. No party offered cross-answering testimony on these issues.

20 On December 20, 2019, Avista filed rebuttal testimony responding to Public Counsel's opposition to the Settlement's natural gas revenue requirement.

21 David J. Meyer, Vice President and Chief Counsel for Regulatory and Governmental Affairs, Spokane, Washington, represents Avista. Jennifer Cameron-Rulkowski, Nash I. Callaghan, Joe M. Dallas, and Daniel J. Teimouri, Assistant Attorneys General, Olympia, Washington, represent Commission staff (Staff).[9] Lisa W. Gafken and Nina Suetake, Assistant Attorneys General, Seattle, Washington, represent the Public Counsel Unit of the Attorney General's Office (Public Counsel). Tyler Pepple and Riley Peck, Davison Van Cleve, P.C., Portland, Oregon, represent AWEC. Simon J. ffitch, Attorney at Law, Bainbridge Island, Washington, represents The Energy Project. Jessica Yarnall Loarie and Gloria D. Smith, Attorneys at Law, Oakland, California, represent Sierra Club. Irion Sanger and Marie Barlow, Sanger Thompson P.C., Portland, Oregon, represent NWEC.

B. ISSUES

22 The Commission is presented with a Settlement that proposes to resolve most issues in dispute, as follows:

- Electric revenue requirement;
- Cost of capital, including capital structure, cost of debt, return on equity, and overall rate of return;
- Electric and natural gas rate spread and rate design;
- ERM refund;
- Colstrip Depreciation and Regulatory Asset, including accelerating depreciation of production plant to 2025, depreciation of transmission assets, decommission and remediation costs for Colstrip Units 3 and 4; recovery of Colstrip production plant and transmission depreciation expense and Colstrip decommissioning and

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[9] In formal proceedings such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

remediation expense, and account balances and depreciation/amortization expense;
- Low-income weatherization funding;
- LIRAP funding;
- Disconnection reduction plan;
- On-bill repayment/financing program;
- Deferral amortizations;
- Renewables to benefit low-income;
- Transportation electrification;
- Natural gas special contracts;
- Inland Empire Paper (IEP) special contract;
- Colstrip capital investment limitations;
- Colstrip transmission planning; and
- Colstrip community transition fund.

As discussed above, Avista's natural gas revenue requirement is addressed in the Settlement but contested by Public Counsel.

23 The Commission also resolves several other contested matters, including decoupling and several distinct issues related to Avista's ERM, including: bias in net power costs calculations and authorized gas transport revenues; the carrying charge on the ERM deferral balance; and, deferral amounts related to baseline power costs from the remanded Avista 2015 general rate case, Dockets UE-150204 and UG-150205 *(Consolidated)* (2015 Avista Remand Dockets).

24 Finally, the Commission incorporates into this Order its decisions regarding: (1) the mechanism for returning the amount due to customers determined by Order 11 in the 2015 Avista Remand Dockets, and (2) how our decision in Order 05 of Docket UE-190882 affects the ERM deferral balance that must be returned to customers.

DISCUSSION AND DECISION

25 The Commission's statutory duty is to establish rates, terms, and conditions for electric and natural gas services that are "fair, just, reasonable and sufficient." In doing so, the Commission must balance the needs of the public to have safe, reliable, and appropriately priced service with the financial ability of the utility to provide that service. The rates thus must be fair to both customers and the utility; just, in that the rates are based solely on the record in this case following the principles of due process of law; reasonable, in light of the range of potential outcomes presented in the record; and sufficient, to meet the financial needs of the utility to cover its expenses and attract capital on reasonable terms.

A. PARTIAL MULTIPARTY SETTLEMENT STIPULATION[10]

26 The Commission approves settlements "when doing so is lawful, the settlement terms are supported by an appropriate record, and when the result is consistent with the public interest in light of all the information available to the commission."[11] The Commission may approve the Settlement, with or without conditions, or reject it.

27 The Parties reached agreement on most issues presented in these dockets. We address the agreed portions and contested portion of the Settlement, below.

1. UNCONTESTED ISSUES

28 Although uncontested, our statutory obligation to regulate in the public interest requires us to evaluate whether the Parties' agreed resolution of uncontested issues complies with applicable legal requirements, is supported by an appropriate record, and is consistent with the public interest based on all of the information available to the Commission. Our review of the Settlement's proposed resolution of the uncontested issues finds that it is lawful, supported by an appropriate record, and is in the public interest.

i. Electric Revenue Requirement

29 The Parties agree that Avista's electric revenue requirement should be increased effective April 1, 2020, by $28.5 million, or a 5.7 percent base rate increase, prior to any refund of the ERM deferral balance.[12] The electric revenue requirement is a "black box" agreement. This means that the Parties agree that the overall rate increase amount is fair, just, reasonable, and sufficient, but do not agree to any specific adjustments, aside from

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[10] The Settlement is included as Attachment A to this Order. Attachment A is incorporated into, and made part of, this Order by this reference. In this Order, we briefly summarize the Settlement's proposed commitments. To the extent any arguable inconsistency exists between our summary and the terms of the Settlement, the terms of the Settlement (Attachment A) control.

[11] WAC 480-07-750(1).

[12] Settlement at 4, ¶¶ 9, 9(a).

those specifically presented in the Settlement, necessary to reach the agreed electric revenue requirement.

Commission Determination

30 We find that the electric revenue requirement proposed by the Parties is a fair and reasonable outcome, and we are satisfied that the Company's costs justify the $28.5 million rate increase. In its initial filing, Avista proposed an increase to its electric revenue requirement of $45.8 million in the first year of a two-year rate plan. The non-company parties originally opposed Avista's initial filing and provided responsive testimony and evidence supporting electric revenue requirement increases of $17.6 million (Staff), $11.0 million (Public Counsel), and a decrease of $2.7 million (AWEC). These responsive recommendations were each calculated based on the inclusion or rejection of various proposed adjustments and widely varying cost of capital calculations.

31 Because the Settlement proposes a "black box" resolution of the electric revenue requirement, there is no indication by the Parties as to which plant additions are included in or excluded from rate base and the resulting revenue requirement calculation. The Parties will retain the right in future cases, therefore, to contest the recovery of any investment for which Avista sought recovery in this case. By approving the proposed electric revenue requirement, the rate base approved in Avista's prior rate case remains undisturbed and we make no determination relating to prudence or accepting any party's proposed adjustments.

32 We have considered the full record before us in evaluating whether the proposed increase in electric revenue requirement is compliant with applicable legal requirements, supported by an appropriate record, and consistent with the public interest based on all the information available to the Commission. We find that it is. The agreed increase is a fair compromise of the positions of the Parties and the withdrawal of the two-year rate plan retains the Commission's flexibility to address rates prior to the end of that two-year period. We, therefore, determine that the proposed increase in electric revenue requirement of $28.5 million is fair, just, reasonable, and sufficient in light of all information available to the Commission.

33 While the Settlement does not include, and we do not approve, a multi-year rate plan as initially proposed by Avista in this proceeding, we encourage all parties in this proceeding and future proceedings to carefully review the Commission's recently issued

Policy Statement on changes to the used and useful statute.[13] Although our Policy Statement focuses primarily on the process for reviewing utility property by or during the rate effective period, the Commission strongly urges all parties to consider multi-year rate plans in future proceedings.

ii. Cost of Capital

34 The Parties agree to a capital structure for Avista that includes 48.5 percent equity and 51.5 percent debt, an authorized return on equity (ROE) of 9.40 percent, and an authorized cost of debt of 5.15 percent. Application of these factors results in an overall authorized rate of return (ROR) of 7.21 percent, as reflected in Table 1, below.[14]

Table 1. Proposed Cost of Capital

	Capital Structure	**Cost**	**Weighted Cost**
Total Debt	51.5%	5.15%	2.65%
Equity	48.5%	9.40%	4.56%
Overall Rate of Return	100.0%		7.21%

35 Avista's currently approved cost of capital is shown in Table 2, below.

[13] *In re Commission Inquiry into the Valuation of Public Service Company Property that Becomes Used and Useful After Rate Effective Date*, Docket U-190531, Policy Statement on Property that Becomes Used and Useful After Rate Effective Date (Jan. 31, 2020).

[14] Settlement at 4, ¶ 10.

Table 2. Currently Authorized Cost of Capital

	Capital Structure	Cost	Weighted Cost
Long-Term Debt	48.6%	5.76%	2.80%
Short-Term Debt	2.9%	3.26%	0.09%
Equity	48.5%	9.50%	4.61%
Overall Rate of Return	100.0%		7.50%

Commission Determination

36 We find that the cost of capital proposed by the Parties is a fair and reasonable outcome that is consistent with recent cases before the Commission involving other Washington utilities.

37 Cost of capital is an important factor for the calculation of revenue requirement. All elements of cost of capital (as seen in Tables 1 and 2, above) have an impact on the ultimate calculation of a company's revenue requirement. For example, increases or decreases to ROR and ROE have a corresponding effect on a company's revenue requirement. Holding all other adjustments constant, variations in these factors can result in a difference of millions of dollars in revenue requirement.

38 In this case, Avista initially proposed an increase to its ROR, from 7.50 percent to 7.52 percent, and to its ROE, from 9.5 percent to 9.9 percent. Other parties filed responsive testimony and exhibits supporting ROR calculations ranging from 6.90 percent (AWEC) to 7.15 percent (Staff), and ROE calculations ranging from 8.8 percent (AWEC) to 9.3 percent (Staff). In the Settlement, the Parties agree to an overall ROR of 7.21 percent, which is: (1) consistent with rates of return the Commission has approved for other Washington utilities,[15] (2) 31 basis points lower than the Company's original request, and (3) 31 basis points higher than the ROR proposed by AWEC. We conclude that this is a fair and reasonable outcome, and that it contributes to

[15] *See, e.g., Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corp.*, Docket UG-190210, Order 05 (Feb. 3, 2020) (ROR of 7.31 percent for Cascade); and *Wash. Utils. & Transp. Comm'n v. Northwest Natural Gas d/b/a NW Natural*, Docket UG-181053, Order 06 (Oct. 21, 2019) (ROR of 7.161 for NW Natural Gas).

calculating a revenue requirement that is fair, just, reasonable, and sufficient. Although this is a "black box" agreement, we appreciate that the Settlement specifies the agreed-upon capital structure, ROE, and cost of debt. Establishing these elements, even by agreement, clarifies how the ROR was calculated.

iii. Rate Spread and Rate Design

39 The Parties agree to Avista's initially proposed rate design with a single modification: Schedule 25 will use the proposal described by AWEC witness Kaufman in Exhibit LDK-1T, which will apply the revenue increase for Schedule 25 to fixed and variable demand charges, and also to the 60kV – 115kV and the 115kV or higher primary voltage discounts.[16] With respect to rate spread, the Parties agree to allocate a larger portion of the electric revenue requirement increase to residential customers, but to spread equally any natural gas revenue requirement increase across all customer classes.

40 The electric and natural gas rate spread proposed by the Settlement is presented in Tables 3 and 4, below.

Table 3. Proposed Electric Rate Spread

Rate Schedule	Increase in Base Rates	Increase in Base Rates	Increase in Billing Rates
Residential Schedules 1/2	$ 14,579	6.7%	6.5%
General Service Schedules 11/12	$ 2,131	2.8%	2.6%
Large General Service Schedules 21/22	$ 7,135	5.7%	5.2%
Extra Large General Service Schedule 25	$ 3,789	5.7%	5.5%
Pumping Service Schedules 31/32	$ 684	5.7%	5.2%
Street & Area Lights Schedules 41-48	$ 182	2.8%	2.7%
Overall	$ 28,500	5.7%	5.4%

[16] Settlement at 4-5, ¶ 11.

Table 4. Proposed Natural Gas Rate Spread

Rate Schedule	Increase in Base Rates	Increase in Base Rates	Increase in Billing Rates
General Service Schedules 101/102	$ 6,187	8.7%	5.5%
Large General Service Schedules 111/112/116	$ 1,515	8.7%	4.3%
Interrupt. Sales Service Schedules 131/132	$ 17	8.7%	3.9%
Transportation Service Schedule 146	$ 281	8.7%	8.6%
Special Contracts Schedule 148	$ -	0.0%	0.0%
Overall	$ 8,000	8.5%	5.2%

Commission Determination

41 We find that the rate spread and rate design proposed by the Parties are fair, just, and reasonable. Determining an appropriate rate spread requires consideration of several factors and not simply the result of pure arithmetic. We consider the results of a valid cost of service study with the goal of ensuring that each customer class bears the burden of the costs it imposes on the utility. The Commission also considers, as appropriate, such factors as fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability.

42 In this case, we find the Parties' agreement is fair and balanced. We agree with the joint testimony in support of the Settlement submitted on behalf of Public Counsel that "[r]ate spread, as a general concept, is independent of revenue requirement."[17] Moreover, we agree with the Parties that it is fair and equitable for residential customers to incur a slightly larger share of the electric revenue requirement increase as it brings the electric residential class closer to parity, and for the natural gas revenue requirement increase to be spread to all classes based on an equal percentage increase on margin, as provided in the Settlement, maintaining the status quo during the pendency of the Commission's Cost of Service Rulemaking.[18] The balanced approach on both the electric and natural gas rate

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[17] Dahl, Exh. JT-1T at 46:5-7.

[18] On July 19, 2018, the Commission filed with the Code Reviser a Preproposal Statement of Inquiry (CR-101) in Dockets UE-170002 and UG-170003 to examine the extent to which cost of service studies should be defined by rule, and address policy issues regarding the methods and

spread and rate design is consistent with principles of both fairness and gradualism. Accordingly, we determine that the Settlement's proposal for rate spread and rate design is in the public interest.

iv. Method for Returning ERM Deferral Balance

43 Avista's ERM, Docket UE-190222, is consolidated with the GRC Dockets. We determine the amount of the ERM deferral balance that must be returned to customers in Section C.2. of this Order. Here, for the purposes of settlement, the Parties agree that the ERM deferral balance — except for $0.5 million, which will be applied to the accelerated Colstrip production plant depreciation expense of $2.6 million — will be returned to customers through Tariff Schedule 93 over two years beginning April 1, 2020.[19] The Parties also agree to allocate the refund amounts across rate schedules as proposed by Avista witness Ehrbar in Exhibit PDE-1T (ERM).[20]

Commission Determination

44 We find that the method proposed by the Parties for returning the ERM deferral balance is fair and reasonable. Returning the ERM deferral balance to customers through a separate tariff schedule affords transparency and effective tracking to ensure that customers receive the full benefit of the return of the deferral balance. In addition, applying $0.5 million of the ERM deferral balance, along with $1.5 million in other benefits discussed later, to offset the accelerated Colstrip production plant depreciation expense of $2.6 million is reasonable because it will lessen intergenerational inequity. Accordingly, we determine that the Settlement's proposal for returning the ERM deferral balance to customers is in the public interest.

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practices used to calculate and present cost of service studies. WAC 480-07-510(6) currently requires cost studies in general rate proceedings, but does not specify how such cost studies must be prepared or presented. The Commission's inquiry in Dockets UE-170002 and UG-170003 will evaluate the extent to which cost studies can be standardized, the core principles and methods cost studies should utilize, how to streamline the implementation of rates based on a cost study, and the information necessary to ensure an accurate and uniform understanding of the principles upon which a cost study should be based.

[19] Settlement at 5-6, ¶ 12.

[20] *See* Ehrbar, Exh. PDE-1T (ERM) at 6:6-9.

v. Colstrip Units 3 and 4

45 On April 3, 2019, the Commission issued Order 04 (Modified), Approving Settlement Stipulation Subject to Condition (Order 04), in Dockets UE-180167 and UG-180168 *(Consolidated)*.[21] In that order, we rejected a portion of a full settlement presented by the parties related to the use of unprotected excess deferred income tax (EDIT) benefits and the remaining undepreciated balance for Colstrip Units 3 and 4. We determined in that order that it was inappropriate to consider the settlement's proposal because we could not, at that time, measure the impact it would have on rates in the context of all other rate adjustments. We decided, therefore, that the proposal should be considered as part of Avista's next general rate case.[22]

46 Elements rejected as part of the settlement in Dockets UE-180167 and UG-180168 *(Consolidated)* have been included in this Settlement. We address them, and all other portions of the Settlement regarding Colstrip Units 3 and 4, below.[23]

a. Depreciation and Regulatory Asset

47 The Parties agree to accelerate the depreciation schedule for Colstrip Units 3 and 4 production plant from 2034 and 2036, respectively, to 2025 for both units. The balance for production plant, as of March 31, 2020, is approximately $50.0 million, but does not include amounts for any plant additions to Colstrip after December 31, 2017, including SmartBurn. Consistent with RCW 19.405.030, the Settlement does not accelerate depreciation schedules for transmission assets and production plant decommissioning and remediation (D&R) costs to 2025. In the Settlement, D&R costs include the cost of removal and asset retirement obligations.

48 The Parties also agree to depreciate Colstrip transmission assets, including transmission D&R, consistent with the depreciation rates for non-Colstrip transmission assets approved by Order 04. As of March 31, 2020, the balance of undepreciated transmission

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[21] *In re Petition of Avista Corp. d/b/a Avista Utils.*, Dockets UE-180167 and UG-180168 *(Consolidated)*, Order 04 (Modified), Approving Settlement Stipulation Subject to Condition (Apr. 3, 2019).

[22] Settlement at 6, ¶ 13(a).

[23] *Id.*

plant is approximately $11.5 million, and projected transmission D&R costs are approximately $4.8 million.[24]

49 The Parties agree to place D&R costs for Colstrip Units 3 and 4 production plant into a regulatory asset (Colstrip D&R Regulatory Asset). Production plant D&R costs are approximately $33.0 million as of March 31, 2020. Avista will track D&R expenditures and true-up D&R cost projections to ensure that Avista recovers only the actual D&R costs the Commission determines were prudently incurred. The Settlement provides that Avista will file updated D&R projections in each of its GRCs until the end of the remediation process.[25] The Settlement also provides that Avista will update the annual amounts for Colstrip depreciation, amortization of the regulatory asset, and the amortization of Colstrip protected EDIT in each of its GRC filings.[26]

50 The Settlement also addresses recovery of the items explained above.[27] Depreciation expense is currently recovered from customers at the annual rate of approximately $4.5 million. For production plant depreciation expense, the Parties propose to apply the balance of unprotected EDIT benefits, approximately $11.7 million, against the balance of net production plant in service, $50.0 million. The net increase to annual depreciation expense is approximately $2.6 million. This expense, less net amortization of protected EDIT of $0.6 million, will be greatly offset for the rate year by $0.5 million from the ERM deferral balance and $0.9 million residual balance related to the amortization of 2018 temporary tax credits. Colstrip transmission depreciation expense and transmission D&R will continue to be recovered in rates at approximately $0.5 million annually. Last, the Colstrip D&R Regulatory Asset will be amortized over 33 years and nine months consistent with the amortization schedule of protected EDIT.

b. Colstrip Capital Investment Limitations

51 As part of the Settlement, Avista agrees not to support capital expenditures beyond routine capital maintenance costs at Colstrip that will extend the plant's operational life beyond December 31, 2025. The Parties agree that all Colstrip capital expenditures after December 31, 2017, will be subject to a prudence determination in future rate

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[24] Settlement at 6-7, ¶ 13(b).

[25] Settlement at 7, ¶ 13(c).

[26] Settlement at 10, ¶ 13(e).

[27] Settlement at 8-9, ¶ 13(d)(1)-(3).

proceedings and Avista will provide detailed information, including a complete record of the decision making and a full accounting of the costs related to those project expenditures on an annual basis.[28]

c. Colstrip Transmission Planning

52 The Parties agree that Avista will work with other co-owners of Colstrip transmission to resolve questions surrounding the use of Colstrip transmission by future generations after Colstrip Units 1-4 retire. The Parties agree that at least one year prior to closure of Colstrip Units 3 or 4, Avista will develop a transition plan for its Colstrip transmission assets and file it with the Commission. The Settlement also commits Avista to hold at least one workshop with Staff and stakeholders to determine the transition plan's impacts on Washington ratepayers.[29]

d. Colstrip Community Transition Fund

53 The Parties commit to ensuring that residents of Rosebud County, Montana, as well as local governments, labor organizations, and tribal members will receive community transition funding. The Settlement provides $3.0 million in a Colstrip Community Transition fund to be funded 50 percent by shareholders and 50 percent by ratepayers. This money will fund grants for local organizations that will help the community transition away from economic activity related to coal-fired generation, such as education, worker re-training, low income energy efficiency or renewable energy programs. The Parties agree that the $3.0 million in this fund places no limit on the amount Avista may ultimately contribute toward community transition.[30]

Commission Determination

54 We find that the Settlement's proposals related to Colstrip Units 3 and 4 are fair, just, and reasonable. We are familiar with many of these elements from the settlement previously proposed and considered in Order 04. We can now review how many of the elements previously proposed will affect rates. Additionally, the commitments ensure compliance with Washington law and policy.[31] The Parties' proposal to use the $11.7 million in unprotected EDIT benefits towards the $50.0 million net production plant in service

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[28] Settlement at 12-13, ¶ 14(j)

[29] Settlement at 13, ¶ 14(k).

[30] Settlement at 13-14, ¶ 14(l)

[31] *See* Chapter 19.405 RCW.

balance is appropriate to reduce rate pressure on customers from the increased costs of accelerating the Colstrip production plant depreciation schedule. Additionally, we agree with Staff that the Settlement "represents a deliberate effort to align the plan for the recovery of Colstrip costs with the requirements of CETA," and that the Settlement seizes the opportunity to find "a solution for the remaining production plant balance for Colstrip," while mitigating intergenerational inequity issues.[32] We find, therefore, that the Settlement's proposals are appropriate and consistent with state law.

55 We are also satisfied that the Settlement fairly offsets expenses with benefits without foreclosing further action in the future, *e.g.*, the potential for future contributions to community transition funding. Accordingly, we determine that the Settlement's proposals for the above issues related to Colstrip Units 3 and 4 are consistent with state law, supported by the record, in the public interest, and result in rates that are fair, just, reasonable, and sufficient.

vi. Other Provisions

56 The Settlement proposes agreements by the Parties on several other issues, some of which have no financial impacts but promote programmatic changes. The Parties agree to provisions concerning an increase in low-income weatherization and LIRAP funding; a disconnection reduction plan; an on-bill repayment or financing program; deferral amortizations; low-income customers and how low-income customers can share in the benefits of renewables; transportation electrification; natural gas special contracts; and the Inland Empire Paper Special Contract. We address each below.

a. Low-Income Weatherization and LIRAP Funding

57 The Parties agree to increase low-income weatherization funding by $650,000, to a total of $3.0 million, effective August 1, 2020. The Parties also agree to increase the community action agencies' administrative rate to 30 percent, with the direct agency project coordination rate representing 20 percent and the agency indirect rate representing 10 percent of that increase. Additionally, the Parties agree that the Energy Efficiency Advisory Group (EEAG) (members include Staff, Public Counsel, NWEC, and The Energy Project) should review these percentages periodically. The Parties agree to increase the total allowance for Health, Safety & Repair from 15 percent to 30 percent of

[32] McGuire, Exh. JT-1 at 33:10-13, 35:14-17, 36:5-6.

a project's total expense.[33] Last, the Parties agree to increase LIRAP funding according to the formula used in the current five-year plan, which allows for an increase of the greater of 7 percent or twice the residential base rate increase.[34]

b. Disconnection Reduction Plan

58 The Parties agree that Avista will gather data on disconnections, as provided in testimony by The Energy Project's witness Collins. Avista agrees to collect and report the disconnection data annually to the Commission and Public Counsel. Avista also agrees to develop a Disconnection Reduction Plan that will limit disconnections prospectively. This plan will be developed with the Energy Assistance Advisory Group, which will deliver a recommendation to the Commission within one year of the date of this Order.[35]

c. On-Bill Repayment or Financing Program

59 The Parties have agreed to a plan for the development of an on-bill repayment or financing program for residential and small business customers. The Parties agree that Avista will work with the EEAG to develop this program with the purpose of filing the program with the Commission for implementation by September 30, 2021. If Avista and the EEAG are unable to agree on a program design, Avista will file a status report with the Commission by September 30, 2021. The Parties agree that the recovery of development costs for any on-bill repayment or financing program will be recoverable from customers, but the method of recovery will be determined in a future general rate case.[36]

d. Deferral Amortizations

60 The Parties agree to the electric and natural gas Fee Free deferral amortization and the natural gas LEAP deferral amortization as filed by Avista witness Andrews in Exhibit EMA-1T.[37] The Fee Free deferral will be amortized over two years beginning April 1, 2020, and will result in an annual amortization expense of $775,000 for electric and $497,000 for natural gas. The natural gas LEAP deferral will be amortized over five years

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[33] Settlement at 10, ¶ 14(a).

[34] Settlement at 10, ¶ 14(b).

[35] Settlement at 10-11, ¶ 14(c).

[36] Settlement at 11, ¶ 14(d).

[37] Settlement at 11, ¶ 14(e).

beginning April 1, 2020, and will result in an annual amortization expense of $1.745 million.

e. Renewables to Benefit Low-Income

61 As part of the Settlement, Avista commits to discuss with the Energy Assistance Advisory Group renewable programs for low-income customers.[38]

f. Transportation Electrification

62 As part of the Settlement, Avista agrees to work with its Electric Vehicle Supply Equipment (EVSE) working group to develop and finalize a plan with the Commission. Avista supports establishing a goal of dedicating 30 percent of program funds to low-income transportation electrification. Avista will also consider transportation electrification impacts in demand response pilots and integrated resource planning.[39]

g. Natural Gas Special Contracts

63 As part of the Settlement, Avista agrees to review by May 1, 2021, all natural gas special contracts to ensure economic feasibility, and will renegotiate any contract not in compliance. The review will not reexamine the bypass feasibility of existing special contract customers.[40]

h. Inland Empire Paper Special Contract

64 The Settlement provides that Inland Empire Paper and Avista will attempt to negotiate a special contract with Staff's participation. If an agreement cannot be reached, Avista and Inland Empire Paper will seek resolution through binding arbitration, the results of which will be filed with the Commission. The effective date of an approved special contract will coincide with the effective date of Avista's next GRC. Parties reserve the rights to address issues arising from the special contract, including lost margins, in a future proceeding.[41]

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[38] Settlement at 11, ¶ 14(f).

[39] Settlement at 11-12, ¶ 14(g).

[40] Settlement at 12, ¶ 14(h).

[41] Settlement at 12, ¶ 14(i).

Commission Determination

65 We find that the Parties' proposals for the items discussed above are fair and reasonable. The Commission has approved similar increases to low-income funding for other Washington utilities, and thus find it appropriate in the instant case. We find that the collaboration proposed by the Settlement to develop and implement various programs is in the public interest. Collaboration between Avista and its low-income stakeholders is valuable because it will encourage cooperative discussions and, potentially, the development of programs that will benefit Avista ratepayers. Accordingly, we determine that the Settlement's proposals for the above issues are in the public interest and, for those with a financial impact, result in rates that are fair, just, reasonable, and sufficient.

66 Although we determine it is not necessary to disturb the Settlement provision increasing the low-income weatherization administrative rate for community action agencies at this juncture, we are significantly concerned that nearly half of the total increase in weatherization funding will be allocated to these higher administrative costs. Although the record does not indicate any Party's specific concerns with this provision of the Settlement, our review shows we do not have adequate data or a clearly demonstrated need for higher administrative rates. We therefore strongly encourage the EEAG to ensure this funding is efficiently spent and periodically reviewed as provided in the Settlement. The continued requests for higher administrative rates also indicate a need for a broader investigation into the structure and administrative efficiencies of community action agencies to ensure that those customers most in need of bill assistance and weatherization will receive direct benefits from the funding we approve.

2. NATURAL GAS REVENUE REQUIREMENT

67 Avista's natural gas revenue requirement is the only issue addressed by the Settlement that Public Counsel, who otherwise joins all other portions of the Settlement, contests. Accordingly, all other parties agree that Avista's natural gas revenue requirement should be increased effective April 1, 2020, by $8.0 million, or an 8.5 percent base rate increase.[42]

68 Public Counsel provided responsive testimony and exhibits supporting an ROR of 6.96 percent, an ROE of 9.0 percent, and an increase to Avista's natural gas revenue requirement of $3.762 million. In testimony and exhibits opposing the Settlement, Public

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[42] Settlement at 4, ¶¶ 9, 9(b).

Counsel witness Crane revised the calculations for Public Counsel's proposed natural gas revenue requirement to include the cost of capital from the Settlement. That revision, holding all other adjustments (proposed by Public Counsel in response) constant, increases Public Counsel's natural gas revenue requirement proposal by approximately $1.32 million, to $5.081 million.

Commission Determination

69 The only Settlement issue requiring our consideration is whether the proposed $8.0 million increase to natural gas revenue requirement results in rates that are fair, just, reasonable, and sufficient or should be rejected in favor of Public Counsel's proposed $5.081 million increase.[43] Similar to the electric revenue requirement, the Settlement's natural gas revenue requirement is a "black box" agreement. The "black box" resolution provides no indication as to which plant additions are included in or excluded from rate base and the resulting revenue requirement calculation, and also preserves for each party, including Public Counsel, the right in future cases to contest the recovery of any investment for which Avista sought recovery in this case. By approving the proposed natural gas revenue requirement, the rate base approved in Avista's prior rate case remains undisturbed and we make no determination relating to prudence or accepting any party's proposed adjustments. We find that the natural gas revenue requirement proposed by the Settlement and opposed by Public Counsel is a fair and reasonable resolution of the issue, and results in rates that are fair, just, reasonable, and sufficient.

70 Public Counsel argues that opposing any adjustment comprising the $8.0 million increase to natural gas revenue requirement is impossible because it is a "black box" agreement. Public Counsel also argues that the $8.0 million increase to natural gas revenue requirement is too large of an increase, resulting in rates that are unfair, unjust, and unreasonable. We disagree.

71 First, the "black box" nature of the natural gas revenue requirement agreement in this case, like the agreement for the electric revenue requirement, raises no concerns. A "black box" revenue requirement agreement that proposes an end result without specifying most, or any, underlying adjustments used to calculate the end result would be troubling only if unsupported by sufficient evidence that the agreed revenue requirement is fair, just, reasonable, and sufficient. No such deficiency exists here. In evaluating settlements, we consider the entire record. Here, the record for our consideration includes

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[43] Crane, Exh. ACC-14T at 4:10-12.

the Settlement and supporting testimony and exhibits, the testimony and exhibits opposing the Settlement, and all initial and responsive testimony and exhibits filed by the Parties.

72 Avista initially filed for a natural gas revenue requirement increase of $12.9 million, based on an ROR of 7.52 percent, in year one of a two-year rate plan. Staff filed responsive testimony and exhibits supporting a one year natural gas revenue requirement increase of $7.0 million, based on an ROR of 7.16 percent. Public Counsel filed responsive testimony and exhibits supporting a one year natural gas revenue requirement increase of $3.762 million, based on an ROR of 6.96 percent. AWEC filed responsive testimony and exhibits supporting an even lower one year natural gas revenue requirement increase of $2.9 million, based on an ROR of 6.90 percent. The Settlement's proposal for a one year increase of $8.0 million to Avista's natural gas revenue requirement falls within the range created by the Parties' recommended natural gas revenue requirement increases.

73 As its counter-proposal to the Settlement's $8.0 million increase to natural gas revenue requirement, Public Counsel proposes an increase to natural gas revenue requirement of $5.081 million, based on its position in responsive testimony modified only by adopting the Settlement's cost of capital and ROR of 7.21 percent. Public Counsel argues that its proposed increase to natural gas revenue requirement would be fair, just, reasonable, and sufficient. We disagree and find that Public Counsel's proposal is neither reasonable nor sufficient.

74 Public Counsel's counter-proposal is based on witness Crane's responsive testimony and exhibits. Crane excludes all of Avista's proposed pro forma major capital additions from its natural gas revenue requirement calculation, arguing that none are known and measurable. Yet in response to Public Counsel's proposal, Avista witness Andrews explains that "many capital projects . . . were already in-service and '<u>known and measurable</u>' as of July 2019; well before the filing of [responsive] testimony on October 3, 2019."[44] The parties were thus given more than eight weeks to analyze capital projects placed in service by July 2019.

75 Accordingly, Public Counsel's refusal to consider these projects is unreasonable. At a minimum, Public Counsel should have analyzed the pro forma capital additions through

[44] Andrews, Exh. EMA-9T at 8:6-9.

July 2019 and recommended which, if any, should be included in Avista's natural gas revenue requirement consistent with Commission standards and precedent.[45] Although we decline to establish a bright line cutoff for inclusion of pro forma additions, we expect parties to consider and analyze any plant placed in service reasonably in advance of the responsive testimony deadline.

76 Notably, Avista witness Andrews argues that accepting Staff's position only on major capital additions would increase Public Counsel's natural gas revenue requirement by nearly $2.2 million, to approximately $7.3 million.[46] Andrews' argument illustrates that Public Counsel's $5.081 million proposed increase to Avista's natural gas revenue requirement would have increased with only a single modification.[47] Public Counsel's carte blanche exclusion of all post-test year pro forma additions lacks both evidentiary and policy support. Accordingly, we find that Public Counsel's recommendation would result in insufficient rates.

77 By contrast, the Settlement's proposal to increase the natural gas revenue requirement by $8.0 million produces a fair, just, reasonable, and sufficient end result. There is ample evidence in the record to support an increase to Avista's natural gas revenue requirement, ranging from $2.9 to $12.9 million. We find that the Settlement's proposal for an increase of $8.0 million, which represents a negotiated compromise of the parties' positions, is a fair and reasonable outcome that is well supported by the evidence in the record.

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[45] *See Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-150204 & UG-150205 *(Consolidated)*, Order 05, Final Order Rejecting Tariff Filing, Accepting Partial Settlement Stipulation, Authorizing Tariff Filings, 17, ¶ 40 (Jan. 6, 2016) *remanded on other grounds, see Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-150204 and UG-150205 *(Consolidated)*, Order 11, Final Order on Remand (Mar. 6, 2020); *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-130043, Order 05, 79, ¶ 198 (Dec. 4, 2013).

[46] Andrews, Exh. EMA-9T at 8:10-14. Staff's position includes some pro forma capital additions that are consistent with Commission precedent, but in responsive testimony Staff argued for a modification to the Commission's materiality threshold and we make no determination as to that modification or any other adjustment that was proposed by a party and now subsumed by the Settlement.

[47] Staff's position would have increased Public Counsel's proposed natural gas revenue requirement by $2.2 million only if we approved the modification to the Commission's materiality threshold. We make no determination regarding Staff's proposed modification. With the exclusion of Staff's modification to the materiality threshold, Staff's position would still have significantly increased Public Counsel's proposed natural gas revenue requirement.

78 Last, we reject Public Counsel's argument that Avista's natural gas ratepayers "have been burdened by significant increases over the last few years," including "increases virtually every year from 2009 to 2016," and that the benefits of recent rate reductions enjoyed by ratepayers since 2018 "will effectively be wiped out if the proposed $8.0 million increase is approved."[48] The period 2009 to 2016 referenced by Public Counsel is less relevant than the period since 2016 for our consideration and balancing of Avista's *current* costs and revenues.[49]

79 Avista's 2015 general rate case decision was remanded to the Commission by the Washington Court of Appeals. As a result of that remand, the Commission ordered Avista to return $4,919,000 to electric customers and $3,571,000 to natural gas customers.[50] Avista's 2016 general rate case resulted in no increase to either the Company's electric or natural gas revenue requirement.[51] Avista's 2017 general rate case resulted in a decrease to Avista's natural gas revenue requirement of $2.1 million.[52] Avista natural gas ratepayers have had consistent or declining rates since 2016, have not suffered multiple recent rate increases, and, as a result of this Order, will be receiving a number of benefits including returns from the 2015 Avista Remand Dockets.

80 Having considered the full record before us, we find that the Settlement's proposed natural gas revenue requirement increase of $8.0 million is supported by the record and results in rates that are fair, just, reasonable, and sufficient.

3. SETTLEMENT DETERMINATION

81 We have reviewed the Settlement, its supporting evidence, and all evidence in the record. Accordingly, we conclude that the resulting rates, terms, and conditions are fair, just, reasonable, and sufficient. The Settlement terms are lawful, supported by an appropriate

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[48] Crane, Exh. ACC-14T at 4:18-5:6.

[49] *See* Crane, Exh. ACC-15.

[50] *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-150204 and UG-150205 *(Consolidated)*, Order 11, Final Order on Remand (Mar. 6, 2020).

[51] *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-160228 and UG-160229 *(Consolidated)*, Order 06, Final Order Rejecting Tariff Filing (Dec. 15, 2016).

[52] *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-170485, UG-170486, UE-171221, and UG-171222 *(Consolidated)*, Order 07/02/02 Final Order Rejecting Tariff Sheets, Approving Partial Settlement, and Directing Company to File Tariff Sheets in Compliance (Apr. 26, 2018).

record, and consistent with the public interest in light of all the information available to the Commission. We therefore approve the Settlement without condition.

B. CONTESTED ISSUES OUTSIDE THE SETTLEMENT

82 The Settlement failed to resolve two contested issues, or categories of issues. First, we must resolve questions regarding Avista's decoupling mechanisms and proposed modifications to those mechanisms. Second, we must resolve the remaining ERM issues in Docket UE-190222 that are not otherwise addressed in the Settlement or Docket UE-190882.

1. DECOUPLING

83 On November 25, 2014, the Commission approved a full settlement with conditions that created Avista's current decoupling mechanisms in Order 05 of Dockets UE-140188 and UG-140189 *(Consolidated)* (2014 GRC).[53] That settlement required Avista to undertake at its own expense a third-party evaluation of the mechanisms at the end of their third full-year. The Commission conditioned approval of the settlement and Avista's decoupling mechanisms on additional conditions related to the third-party evaluation, requiring that Avista:

- Consult with its conservation advisory group to develop the evaluation's request for proposals (RFP) and incorporate the input from its advisory group in a draft RFP;
- File a draft RFP for Commission approval that includes the scope of evaluation query, allowing sufficient time for Commission consideration; and
- Consult with its conservation advisory group on the selection of the entity to perform the evaluation.[54]

On October 1, 2018, Avista filed with the Commission a third-party evaluation by H. Gil Peach & Associates LLC (H. Gil Peach or Independent Evaluator) of its decoupling

[53] *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-140188 and UG-140189 *(Consolidated)*, Order 05, Final Order Rejecting Tariff Filing, Accepting with Conditions Full Settlement Stipulation, Authorizing Tariff Filing, and Requiring Compliance Filing (Nov. 25, 2014).

[54] *Id.* at 14, ¶ 28.

mechanisms in compliance with the Commission's direction in the 2014 GRC final order (Peach or Independent Evaluator Report). The Peach Report is included as part of the record in this case.[55]

84 The Peach Report found that "Avista's decoupling [mechanisms are] working well within the specific window of time examined."[56] The Peach Report's summary and recommendation provides:

> The decoupling mechanisms have worked as expected to stabilize revenue without impacting utility operations and energy efficiency programs. We also found no evidence of adverse impacts to any customer groups. We recommend the electric and natural gas mechanisms be continued and certain modifications be considered.[57]

85 Avista proposed six modifications to its decoupling mechanisms in its initial filing. Some of these modifications arose directly from the Peach Report's recommendations.[58] The majority of Avista's proposals are uncontested, but Public Counsel and NWEC filed responsive testimony and exhibits recommending additional or opposing modifications to Avista's decoupling mechanisms. Staff did not file responsive testimony and supports Avista's proposals.[59] Staff and Avista filed cross-answering and rebuttal testimony and exhibits responding to the modifications recommended by Public Counsel and NWEC. AWEC and The Energy Project did not offer testimony regarding Avista's decoupling mechanisms. We address the parties' contested and uncontested modifications, below.

i. Contested Modifications to the Decoupling Mechanisms

86 NWEC suggests two modifications of which one, related to Avista's conservation targets, is contested. While no party opposes the Company's request to continue its decoupling mechanisms in some form through March 31, 2025, Public Counsel proposes modifying the decoupling mechanisms to either lost revenue adjustment mechanisms (LRAM) or, in

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[55] Ehrbar, Exh. PDE-2, *Avista Decoupling Evaluation Final Report*, H. Gil Peach & Assoc. LLC (Oct. 1, 2018) [hereinafter Peach Report].

[56] *Id.* at 1.

[57] *Id.* at 10-1.

[58] *Id.*; Ehrbar, Exh. PDE-1T at 23:22-24:7.

[59] Jordan, Exh. ELJ-1T at 2:17-18; Ehrbar, Exh. PDE-3T at 2:2-11.

the alternative, rate class decoupling mechanisms. Public Counsel also expressed concern about Avista's proposed treatment of new customers in relation to the decoupling mechanisms.

a. Clarification, LRAM, and Rate Class Decoupling Mechanism

87 Public Counsel witness Crane argues that the Commission's decoupling policy is unclear, and requests the Commission clarify whether its purpose is to ensure utilities recover their authorized revenue requirement or to compensate utilities for sales lost due to energy efficiency programs. Crane critiques Avista's decoupling mechanisms and, depending upon the Commission's clarification, proposes two different mechanisms: a lost revenue adjustment mechanism (LRAM) or a rate class decoupling mechanism. Avista, Staff, and NWEC oppose Public Counsel's proposals.

88 NWEC witness Levin rebuts Public Counsel's decoupling criticisms and argues that Public Counsel's proposal to use an LRAM is inappropriate.[60] Levin explains that Avista's proposal, unlike an LRAM, eliminates the utility's disincentive "to promote or help customers invest in these newer, 'behind-the-meter' clean technologies such as distributed generation."[61] Levin also cites to national data comparing conservation programs of utilities with LRAMs conservation programs to those with full decoupling, concluding that full decoupling ultimately results in greater conservation.[62]

89 Staff witness Jordan argues the Commission's most recent NW Natural Gas rate case order answered the fundamental questions raised by Public Counsel.[63] Jordan opposes Public Counsel's LRAM proposal, arguing that it would require the Commission to limit the purpose of decoupling to the effects of conservation, something the Commission has not done in the past. From a practical standpoint, Jordan argues that the LRAM proposal renders it impossible "to disaggregate the causes of load variations in the way Public Counsel requests."[64]

90 Regarding Public Counsel's proposal for a rate class decoupling mechanism, Staff witness Jordan contends that decoupling deferrals and achieved earnings have only a

[60] Levin, Exh. AML-4T at 1:6-14.

[61] *Id.* at 6:9-6:22.

[62] *Id.* at 7:13-8:5.

[63] Jordan, Exh. ELJ-1T at 6:5-11.

[64] *Id.* at 7:9-11.

tenuous connection, and characterizes Public Counsel's proposal as a revenue sufficiency test.

91 Avista witness Ehrbar opposes Public Counsel's rate class decoupling proposal, arguing that this form of decoupling fixes the total amount of revenue the Company can keep after rates are set. Ehrbar contends that this outcome is contrary to Commission's practice. Ehrbar explains that Public Counsel's decoupling proposal in PSE's 2017 GRC was very similar, and argues that the Commission's bases for rejecting Public Counsel's proposal should be the same in this case.[65]

Commission Determination

92 We decline Public Counsel's invitation to further elaborate on the purpose of decoupling mechanisms. This topic is addressed thoroughly in the Commission's Decoupling Policy Statement and, most recently, in Final Order 06 in Docket UG-181053.[66] We reiterate by incorporation the variety of purposes decoupling mechanisms serve, including usage volatility directly tied to conservation efforts and reducing a utility's disincentive to promote energy efficiency.

93 We have heard and rejected Public Counsel's arguments for an LRAM or rate class decoupling mechanism in earlier proceedings.[67] We reach the same conclusion here. Instead, we approve Avista, Staff, and NWEC's proposal to continue Avista's decoupling mechanisms with the modifications discussed in this Order. The proposal is amply supported by the evidence in the record and comports with, rather than departs from, our past practice. We address and resolve the issue of whether Avista's decoupling mechanisms should be continued for five more years in Section B.1.ii.a. of this Order.

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[65] Ehrbar, Exh. PDE-3T at 11:5-16.

[66] *Wash. Utils. & Transp. Comm'n's Investigation into Energy Conservation Incentives*, Docket U-100522 (Nov. 4, 2010); *Wash. Utils. & Transp. Comm'n v. NW Natural Gas*, Docket UG-181953, Order 06, Final Order Rejecting Tariff Sheets; Approving and Adopting Joint Settlement Agreement; Rejecting Partial Multiparty Settlement Agreement on Decoupling; and Authorizing and Requiring Compliance Filing, 11-18, ¶¶ 29-43 (Oct. 21, 2019).

[67] *See e.g. Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-170033 and UG-170034 *(Consolidated)*,Order 08, Final Order Rejecting Tariff Sheets; Approving and Adopting Settlement Stipulation; Resolving Contested Issues; and Authorizing and Requiring Compliance Filing, 99-102, ¶¶ 289-94 (Dec. 5, 2017); *see also* Ehrbar, Exh. PDE-3T at 6:15-11:16.

b. New Customers

94 In response testimony, Public Counsel witness Crane expressed concerns about Avista's initial proposal to remove the fixed production and transmission costs of serving new customers. Crane argues that, while the proposal would improve the Company's decoupling mechanisms, it will continue to result in over-recovery and "permits recovery of certain costs that almost certainly already being recovered from 'existing' customers."[68] In cross-answering testimony, NWEC witness Levin supports Avista's position, arguing that allowing additional revenue growth from new customers on a revenue-per-customer basis during the rate effective period is appropriate for balancing the increased costs that can occur after rates are set.[69]

95 Responding to Public Counsel's concerns on rebuttal, Avista modified its position and proposed, instead, to exclude new customers from the decoupling mechanisms entirely.[70] According to Avista witness Ehrbar, this proposal will treat revenue for "new customers" the same as it was treated prior to the implementation of the decoupling mechanisms. At hearing, Ehrbar clarified that the Company meant "new meters" when it referred to "new customers." Customers who move in to Avista's service territory, but do not cause the addition of a new meter (as a newly built home or office might cause), will not be excluded from the decoupling mechanisms. Ehrbar also clarified that any new customers would be incorporated into the decoupling mechanisms during the next rate case.[71] Avista believes its proposal reasonably balances the revenues and costs of new customers consistent with the Commission's direction in its Decoupling Policy Statement.[72]

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[68] Crane, Exh. ACC-1T at 55:15-19.

[69] Levin, Exh. AML-4T at 3:8-5:19.

[70] Ehrbar, Exh. PDE-3T at 3:13-14. Avista would exclude new customers after the end of the test year in the instant case, January 1, 2019. At the time of the next GRC, the new customers added since the last GRC will be added to the decoupling mechanisms. *Id.* at 2:14-19 and 5:8-13. Ehrbar notes that the exclusion of new customers proposed here is similar to the exclusion of new natural gas customers under Avista's decoupling mechanism in Oregon. *Id.* at 4:13-15:2.

[71] *Id.* at 2:14-19 and 5:8-13.

[72] *Id.* at 4:6-12.

96 Staff believes that either of the approaches presented in Avista's initial or rebuttal testimony is reasonable and consistent with the Commission's Decoupling Policy Statement.[73]

Commission Determination

97 We find that excluding new customers in their entirety from the decoupling mechanisms, as proposed by Avista, is appropriate in this case subject to limited monitoring and reporting. The Commission noted in its Decoupling Policy Statement the possibility that a utility could earn more than its authorized ROR via additional revenues realized from the addition of new customers. The Commission also emphasized that a decoupling mechanism must strike a balance between the revenues and costs from new customers, and that the Commission would consider excluding all or some new customer revenue. Here, we find that it is necessary to monitor the data for new customers to understand future consequences of excluding them from the decoupling mechanisms. Accordingly, we determine that Avista's proposal to exclude new customers from its decoupling mechanisms should be approved, but that Avista must include a status update in its yearly decoupling report identifying the number of new customers excluded from the decoupling mechanisms and associated costs and revenues from those customers. Additionally, we require the third-party evaluator to include an evaluation of this design component in its evaluation.

c. Conservation Targets

98 In its initial filing, Avista committed to achieving an additional 5 percent above its electric energy efficiency targets with the continuation of its electric decoupling mechanism.[74] The Company has not previously had a similar target associated with its natural gas decoupling mechanism. Avista proposed, however, that with the continuation of its natural gas decoupling mechanism it would commit to achieving an additional 5 percent above the natural gas conservation target required by its natural gas integrated resource plan (IRP).[75] Further, the Company agrees to a penalty if it fails to meet this proposed target on a graduated scale, as follows:

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[73] Staff Brief at 7, ¶ 16.

[74] Ehrbar, Exh. PDE-1T at 11:13-14.

[75] *Id.* at 11:17-12:2.

$20,000 for incremental conservation between 4.5 and 5.0 percent;
$50,000 for incremental conservation between 3.75 and 4.5 percent;
$75,000 for incremental conservation below 3.75 percent.[76]

99 NWEC Witness Levin instead proposes that Avista should achieve an additional 10 percent above its conservation targets, achievable on either the electric or natural gas side, in lieu of separate 5 percent targets for each of the electric and natural gas decoupling mechanisms.[77] Levin reasons that NWEC's proposal "would provide more flexibility for Avista to procure the most cost-effective end-use equipment and measures, no matter the fuel, in the future given policies and prices."[78] Levin argues that growing efforts to price greenhouse gas emissions and efforts to ban new gas hookups raise concerns about "locking" customers into long-lasting equipment and infrastructure.[79]

100 Avista and Staff oppose NWEC's proposal. Staff witness Jordan argues that the proposal amounts to inter-business subsidization between the electric and the natural gas operations, which has been previously rejected by the Commission.[80] Jordan argues that the reasons NWEC offers to support the additional 5 percent are not related to the operation or purpose of the decoupling mechanism.[81] Avista witness Ehrbar argues on rebuttal that the natural gas target is consistent with targets approved by the Commission for other Washington utilities and that, because the commitment to achieve additional natural gas conservation is new, it is "premature to have a target above 5 percent."[82]

Commission Determination

101 We agree with Avista and Staff. In general, we find that it is appropriate to avoid inter-business subsidization and that natural gas conservation targets should be connected to

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[76] *Id.* at 11:22-12:2.

[77] Levin, Exh. AML-1T at 14:14-19.

[78] *Id.* at 18:9-12. NWEC proposes the 10 percent be the simple addition of the percent by which the Company exceeded its electric target and the percent by which the Company exceeded its natural gas target. *Id.* at 18:20-19:2.

[79] *Id.* at 18:6-10.

[80] Jordan, Exh. ELJ-1T at 10:13-15 (citing *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-170485, UG-170486, UE-171221, and UG-171222 *(Consolidated)*, Order 07, 94, ¶ 285 (Apr. 26, 2018)).

[81] *Id.* at 10:17-11:15.

[82] Ehrbar, Exh. PDE-3T at 6:11-14.

the natural gas decoupling mechanism. NWEC's proposal to create a combined 10 percent conservation target for Avista decoupling mechanisms, weakens the connection between Avista's natural gas conservation efforts and its natural gas decoupling mechanism and also results in inter-business subsidization that has not been sufficiently justified in this proceeding. Although we understand NWEC's position that fewer fossil fuels may be used to provide energy to Washington customers at some point in the future, we agree with Avista that the argument is premature at this juncture. Accordingly, we do not foreclose future consideration of modified conservations targets if demonstrated to be appropriate in future cases. No such showing has been made here. To the contrary, we find that Avista has established that a 5 percent conservation target for its natural gas business is appropriate. Accordingly, we determine that a separate 5 percent conservation target for each of the electric and natural gas decoupling mechanisms is fair, reasonable, and in the public interest.

ii. Uncontested Modifications to the Decoupling Mechanisms

102 The remaining proposed modifications to the decoupling mechanisms are uncontested. We approve some and reject others, as we explain below.

a. Continuation of Mechanisms

103 Avista requests authorization from the Commission to continue its decoupling mechanisms for both electric and natural gas through March 31, 2025. No party opposes a five-year continuation of Avista's mechanisms.

Commission Determination

104 The Commission first authorized Avista's decoupling mechanisms for a period of five years. We find that extending the mechanisms with the modifications required by this Order for another five years is reasonable. The Commission will evaluate the mechanisms again after they have operated for five years, which we find is appropriate in light of the modifications required by this Order. Accordingly, we determine that continuing Avista's decoupling mechanisms until March 31, 2025, is in the public interest and will result in rates that are fair, just, reasonable, and sufficient.

b. 20-Year Moving Average of Weather Data

105 In responsive testimony, NWEC witness Levin recommends Avista move from a 30-year moving average of weather data to a 20-year moving average in its next rate case.[83] Levin asserts that Avista could also maintain moving averages based upon a 30-, 15-, and 10-years to understand the impacts and implications of these different averages.[84] Levin contends that weather is one of the two main drivers of per-customer usage, and that a 20-year moving average in response to warming weather trends could help reduce over-forecasting of sales and under-recovery of fixed costs.[85] NWEC argues that in two of the last three years the residential natural gas decoupling adjustment surcharge reached its 3 percent annual cap, warning that this pattern could "result in cost recovery issues if the Company continues to see lower-than-expected sales resulting in persistent deferrals that cannot be recovered in a timely manner through the decoupling mechanism."[86]

Commission Determination

106 NWEC's proposal is generally consistent with the Peach Report's recommendations to consider changes to normal weather and no party opposes it. We nevertheless find that the record is insufficient in this proceeding to adopt a 20-year moving average for decoupling. In addition, this proposal would create inconsistency among Commission regulatory practices beyond Avista's decoupling mechanisms. For example, 30-year weather data is used in weather normalization calculations in rate cases and in integrated resource planning models, among other areas of utility regulation. Changing the basis of weather data from a 30-year to a 20-year moving average would, therefore, have a significant impact on the Commission's regulation of electric and natural gas utilities. Such a change should be thoroughly evaluated and only applied after careful consideration of the broad effect it would have on the Commission's regulatory practice. Here, the record is insufficient to support such a significant change. We agree with NWEC, however, that having comparative data for 30-, 20-, 15-, and 10-year moving averages would help the Commission understand the impacts and implications of various moving weather averages on decoupling. In addition, we encourage Staff to initiate a workshop discussion with stakeholders to discuss whether a 20-year weather average is appropriate across regulatory and utility practice. Accordingly, we require Avista to

[83] Levin, Exh. AML-1T at 14:14-19.

[84] *Id.* at 16:18-19.

[85] *Id.* at 16:13-18.

[86] *Id.* at 16:9-12.

maintain and present data and a brief explanatory narrative for 30-, 20-, 15-, and 10-year moving averages for purposes of decoupling in its annual decoupling report.

c. Reporting Exemption

107 Avista also petitioned in this rate case for an exemption from WAC 480-90-275, which requires each gas utility to file a report of actual results for Washington operations within 45 days of the end of each quarter. Avista requests permission to file its natural gas decoupling report at 60 days instead of 45 days. This would align the filing of natural gas decoupling reports with those for electric decoupling, which are already required to be filed within 60 days of the end of each quarter.[87]

Commission Determination

108 WAC 480-07-110 provides that the Commission "may grant an exemption from, or modify the application of, any of its rules in individual circumstances if the exemption or modification is consistent with the public interest, the purposes underlying regulation, and applicable statutes."[88] We find that granting the requested exemption for the purposes of Avista's natural gas decoupling report meets each of these requirements. The Company files its electric decoupling report within 60 days of the end of each quarter, which avoids conflict with the release of Avista's financial earnings reports. Its filing of its natural gas decoupling report, however, did conflict with the release of Avista's financial earnings reports throughout the first three years of Avista's decoupling mechanisms that necessitated Avista to file a redacted, confidential version of its natural gas decoupling report within 45 days and then refile a fully unredacted version when it filed its electric decoupling report. At hearing, Avista witness Ehrbar clarified that the exemption Avista seeks is solely for its natural gas decoupling mechanism reporting. We find that granting Avista's request is consistent with the public interest, the purposes underlying regulation, and applicable statutes. Accordingly, we determine that Avista's request for an exemption from WAC 480-90-275 should be granted as it applies to the filing of Avista's natural gas decoupling report.

[87] *See* WAC 480-100-275.

[88] *See* WAC 480-90-008.

d. Other Uncontested Modifications

109 No party objects to Avista's proposal to move the effective date of its annual decoupling tariff revisions from November 1 to August 1, and modifying the annualized true-up. We discuss each below.

110 Avista requests the Commission move the decoupling tariff effective date from November 1 to August 1 of every year. The Peach Report recommended moving the effective date from November 1 to July 1, but Avista modified that recommendation to August 1 to coincide with its annual Demand Side Management rate adjustment filings in order to minimize the number of annual rate changes for customers. Moving the tariff effective date, as explained in the Peach Report and by Avista witness Ehrbar in Avista's initial filing, will increase the likelihood that reported revenue would be collected within two years as required by the Securities and Exchange Commission and will allow Avista to report expected earnings that might not otherwise be recognized under Generally Accepted Accounting Practice (GAAP) rules, which require that revenues must be recovered within 2 years of the deferral period.[89]

111 Avista proposes to continue using the 12-month deferral calculation in the annual true-up, but also add a comparison of the annual decoupled revenue per customer to the actual deferred revenue. Avista witness Ehrbar argues that the proposed modification better matches the authorized annual revenue per customer to actual annual revenue per customer.[90]

Commission Determination

112 We find that each of these modifications is fair and reasonable. First, moving the decoupling tariff effective date from November 1 to August 1 is fair to customers and the Company, and will better allow Avista to report expected earnings according to GAAP rules, and thus recover revenues within two years of the deferral period. While the Peach Report recommended an effective date of July 1, we agree with the Company that August 1 is a better date for customers because it coincides with Avista's annual Demand Side Management rate adjustment filings and will result in fewer potential rate changes for customers. No party opposes these modifications. Accordingly, we determine the

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[89] Ehrbar, Exh. PDE-1T at 26:13-27:13.

[90] *Id.* at 28:2-4.

above modifications to Avista's decoupling mechanisms are in the public interest and should be approved.

e. Third-Party Evaluation

113 As part of the 2014 GRC authorization of Avista's previous decoupling mechanisms, the Commission required a third-party evaluation after three years. No party raised a proposal for another third-party evaluation of Avista's decoupling mechanisms during the next 5-year authorization period. We will evaluate the mechanisms approved by this Order after five years and, to aid our evaluation of the operation of the mechanisms, we determine that a third-party evaluation of the decoupling mechanisms is necessary and appropriate in light of the modifications required of the mechanisms by this Order.

114 We, therefore, require a third-party evaluation of the decoupling mechanisms, paid for by Avista shareholders, after three years. As mentioned briefly above, the third-party evaluation of Avista's decoupling mechanisms must include an analysis of the following elements:

- the mechanisms' impact on conservation achievement;
- the mechanisms' impact on Company revenues; and,
- the extent to which fixed costs are recovered in fixed charges for the customer classes.

In addition, we require the third-party evaluator to include an analysis of the effects of:

- Excluding new customers from the decoupling mechanisms;
- Using a moving average of weather data shorter than 30 years based on the data gathered by Avista regarding a 30-, 20-, 15-, and 10-year moving average; and,
- The 3 percent cap on annual adjustments compared with (1) a 5 percent cap, had it been implemented as we have approved for other utilities in Washington, and (2) no cap on annual adjustments.

115 We also require the Company to consult with its EEAG in the development of the Request for Proposals (RFP) and the selection of the third-party evaluator. We require Avista to file its draft RFP, including a scope of the evaluation query, with the Commission for approval allowing sufficient time for Commission consideration.

2. ENERGY RECOVERY MECHANISM

116 Most of the issues concerning Avista's ERM were either uncontested, resolved as part of the Settlement, or resolved in Docket UE-190882. Public Counsel and AWEC contest several outstanding issues. Public Counsel addresses bias in Avista's power cost calculations, and AWEC presents issues regarding (1) the carrying charge on the ERM deferral balance, and (2) deferral amounts related to baseline power costs arising in the 2015 Avista Remand Dockets.

i. Power Costs Bias and Workshops

117 In responsive testimony, Public Counsel witness Avi Allison identifies bias in Avista's net power costs calculations and authorized gas transport revenues. Allison argues that the Commission recognized this bias in Avista's 2017 GRC and directed Avista to engage in the current series of ongoing workshops. Public Counsel requests that the Commission re-affirm that Avista's net power cost calculations are directionally biased, continue to support the stakeholder workshop process, and require the Company to correct identified errors and biases in its net power costs calculations no later than its next GRC.[91] Allison argues that the Company's 2018 actual net power costs suffered from the same directional bias as in years past.[92]

Commission Determination

118 We find it unnecessary to reassert the determinations made in Avista's 2017 rate case. Public Counsel is correct that we ordered the currently ongoing series of power cost workshops. The Parties testify to the value of these workshops and the prospect that the workshops will resolve stakeholder concerns. We encourage the Parties and stakeholders to continue their collaborative efforts and trust that the workshops will bring the parties' concerns to a speedy and successful conclusion. In general, we find it unnecessary to require resolution prior to Avista's next GRC, but we expect the Parties to be able to resolve many, if not all, issues through the power costs workshops and apply those findings in Avista's next GRC. We determine that the Commission need not reassert any declaration of bias already asserted in Avista's 2017 rate case, but we emphasize our continued support for the workshop process and encourage the progress being made by the Parties and stakeholders. In addition, we require Avista to provide a status update

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[91] Allison, Exh. AA-1T at 3:2-8.

[92] *Id.* at 5:3-8.

within three months of the date of this Order regarding the agreed-upon power supply modeling consultant, E3, and its development of a study.

119 Neither the Settlement nor testimony supporting the Settlement addresses the authorized power supply baseline. Avista witness Vermillion testified in Avista's initial filing that the Company does not propose to update power supply costs. We find that no change to the power supply baseline is necessary, particularly in light of our decision to continue to support party and stakeholder collaboration to resolve these issues in the power costs workshops.

ii. Carrying Charge on ERM Deferral Balance

120 As a result of the Parties' agreement in the Settlement regarding treatment of the ERM deferral balance, which accepts AWEC's recommendation that the deferral balance be returned to customers over a two-year period beginning April 1, 2020, the only remaining contested issue is the appropriate interest rate to apply to the deferral balance. In responsive testimony, AWEC witness Mullins recommends that the Commission remove the tax adjustment to the cost-of-debt rate Avista uses to calculate the ERM interest accruals and, instead, use the straight cost of debt without an offsetting net-to-gross adjustment for taxes.[93]

121 Avista opposes AWEC's recommendation by demonstrating that its own interest rate calculation yields results identical to AWEC's. Avista shows that its calculation also offsets the ERM deferral balance with associated accumulated deferred income taxes consistent with the Commission's order establishing the ERM in Docket UE-011595.[94]

122 In its brief, AWEC withdrew its recommendation based on Avista's clarification of its calculation.[95]

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[93] Mullins, Exh. BGM-12T at 5:16-9:16; AWEC Brief at 2, ¶ 5.

[94] Andrews, Exh. EMA-8T at 5:7-7:19; AWEC Brief at 2, ¶ 5; *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Docket UE-011595, 5th Supp. Order, Rejecting Tariff Filing; Approving and Adopting Settlement Stipulation; Authorizing and Requiring Compliance Filing, Appendix A at 6-7, II.4. (Jun. 18, 2002).

[95] AWEC Brief at 2, ¶ 6.

Commission Determination

123 This issue is no longer contested by any party. In light of the evidence in the record, we find that Avista has shown that it has correctly calculated the carrying charge consistent with the Commission's order establishing the ERM in Docket UE-011595. Accordingly, we approve Avista's calculation of the carrying charge for the ERM.

iii. Remand Deferral Amounts Related to Baseline Power Costs

124 AWEC witness Mullins argues that the Commission should increase deferral amounts related to baseline power costs from the 2015 Avista Remand Dockets. Mullins requests that if the Commission does not account for the $12.3 million of disputed power costs from the Remand, then the Commission should increase the deferral balance in the ERM to ensure that Avista is not provided a "windfall."[96]

125 Avista witness Andrews takes issue with AWEC's recommendation to recalculate the authorized level of power supply. Andrews testifies that the Company accurately reflected the current level of authorized power supply expense. Further, Andrews argues that the $12.3 million is not at issue in this proceeding and is outside the scope of the annual review proceeding.

Commission Determination

126 We agree with Avista that this this issue exceeds the scope of this proceeding. The Commission recently issued Order 11 in the 2015 Avista Remand Dockets, which resolved this issue.[97] Accordingly, we determine that this issue is not properly before us in this proceeding.

C. INCORPORATION OF REMAND AND PRUDENCY DECISIONS

127 The Company's approved revenue increase in this proceeding is offset by the results of two recent Commission Orders. First, to avoid multiple rate changes within a single month, the Commission determined in Order 11, resolving the 2015 Avista Remand Dockets, that the amount returned to customers from that decision should be incorporated

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[96] Mullins, Exh. BGM-12T at 10:6-16.

[97] *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-150204 and UG-150205 *(Consolidated)*, Order 11, Final Order on Remand, 12-13, ¶¶ 40-43 (Mar. 6, 2020).

into this Order and go into effect on April 1, 2020.[98] Second, the Commission determined in Order 05 in Docket UE-190882 that $3.3 million in replacement power costs related to the 2018 Colstrip outage should not be recovered from Avista's Washington ratepayers. The Commission directed that amount to be included in the calculation of Avista's ERM deferral balance in these consolidated dockets. We include in this Order, therefore, the total amount of Avista's ERM deferral balance that must be returned to ratepayers.

1. REMAND RETURN

128 In Order 11 in the 2015 Avista Remand Dockets, the Commission ordered Avista to return $4,919,000 to its electric customers and $3,571,000 to its natural gas customers.[99] The Commission also indicated that it would "determine how [Avista] must distribute the refund in [Avista's 2019 rate case]. In light of the timing of [Order 11], incorporating the refunds into any changes the Commission makes to Avista's rates in the 2019 Rate Case is more administratively efficient and would reduce the likelihood of customer confusion."[100]

129 The Commission also determined in Order 11 in the 2015 Avista Remand Dockets that the distribution of $4,919,000 to electric customers and $3,571,000 to natural gas customers should be consistent with the rate spread the Commission approved in Order 05 in the 2015 Avista Remand Dockets.

130 We find that the distribution should occur through credits in separate electric and natural gas tariffs to promote tracking and transparency. Additionally, we find that the amounts should be distributed over a period of one year beginning April 1, 2020, to align the refund with the other modifications to Avista's rates in this case and to reduce the economic impacts an increase to rates would cause Avista ratepayers during the emergent circumstances resulting from the COVID-19 pandemic. We determine, therefore, that Avista must return $4,919,000 to electric customers and $3,571,000 to natural gas customers over the course of a single year through separate tariffs.

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[98] *Id.* at 22, ¶ 73.

[99] *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-150204 and UG-150205 *(Consolidated)*, Order 11 at 25, ¶ 102.

[100] *Id.* at 22, ¶ 73.

2. ERM DEFERRAL BALANCE

131 When Avista initially filed Docket UE-190222, the ERM deferral balance was estimated at approximately $34.4 million. That balance has continued to accrue interest. At hearing, the Commission requested through Bench Request No. 1 that Avista provide the expected ERM deferral balance as of April 2020 and the expected amortization amount to be rebated over the Settlement's agreed upon two-year period. Avista's response to Bench Request No. 1 indicated an estimated balance of $36.3 million as of March 31, 2020. Pursuant to the Settlement, $0.5 million of that balance is applied to accelerated Colstrip production plant depreciation expense pursuant to the Settlement's terms, resulting in an estimated balance of approximately $35.8 million.

132 As a result of the 2018 Colstrip outage, Avista incurred an additional $3,274,000 in replacement power costs, which the Commission determined in Order 05 of Docket UE-190882 cannot be recovered from Avista's Washington ratepayers. According to the Settlement's terms, which we approve, the total ERM deferral balance is calculated by incorporating this approximately $3.3 million with the estimated balance of approximately $35.8 million and will be returned to ratepayers over two years. In response to Bench Requests No. 1 and No. 3, Avista and Staff propose calculations to return the total ERM deferral balance in equal portions over two years. The apportionment of the ERM deferral balance between the first and second year is not, however, addressed in the Settlement.

133 Under normal circumstances we would accept and adopt the calculations Avista and Staff propose. However, following the closing of the record in this case, the Governor on February 29, 2020, issued a Declaration of Emergency, noting the health and economic impacts to Washington citizens resulting from the outbreak of COVID-19. Under these circumstances, we find that rather than returning an equal portion of the ERM deferral balance over two years, which would result in a rate increase to electric customers during this difficult time, the better course of action is to return a greater portion of the ERM deferral balance in the first year to achieve a net zero revenue requirement impact beginning April 1, 2020.

134 To achieve this result, Avista must calculate the portion of the ERM deferral balance to be returned to customers following the method Avista and Staff used to arrive at a deferral balance of approximately $42.4 million in response to Bench Request No. 3.[101] In conjunction with the Settlement's $28.5 million increase to Avista's electric revenue requirement and the return of approximately $4.9 million to electric customers from the 2015 Avista Remand Dockets over one year, Avista must modify the apportionment of the ERM deferral balance such that there is no net increase to Avista's electric revenue requirement beginning April 1, 2020. Accordingly, we approve the 2018 ERM deferral entries and determine that the ERM deferral balance and the apportionment of the balance we require is fair, just, reasonable, sufficient, and in the public interest.

D. CONCLUSION

135 The Commission's statutory duty is to establish rates, terms, and conditions for electric and natural gas service that are "fair, just, reasonable and sufficient."[102] In doing so, the Commission must balance the needs of the public to have safe, reliable, and appropriately priced service with the financial ability of the utility to provide that service. The resulting rates thus must be fair to both customers and the utility; just, in that the rates are based solely on the record in this case following the principles of due process of law; reasonable, in light of the range of potential outcomes presented in the record; and sufficient, to meet the financial needs of the utility to cover its expenses and attract capital on reasonable terms.[103]

136 We determine that approval of the Settlement, without condition, in concert with the other findings we have made and explained, above, establish rates, terms, and conditions for Avista's electric and natural gas service that are fair, just, reasonable, and sufficient.

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[101] In response to Bench Request No. 3 Avista's narrative (and Attachment E) and Staff's Result D both calculate, using a $3.3 million disallowance from Docket UE-190882, an ERM deferral balance after sharing of approximately $42.4 million with approximately $21.2 million returned to customers in year one and approximately $21.3 million returned to customers in year two.

[102] RCW 80.28.010(1); RCW 80.28.020.

[103] *See generally Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W.V.,* 262 U.S. 679 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591 (1944); *People's Org. for Wash. Energy Res. v. Wash. Utils. & Transp. Comm'n*, 104 Wn.2d 798, 807-13 (1985) (describing rate setting process in Washington).

FINDINGS OF FACT

Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

137 (1) The Commission is an agency of the State of Washington vested by statute with the authority to regulate rates, regulations, practices, accounts, securities, transfers of property and affiliated interests of public service companies, including electric and natural gas companies.

138 (2) Avista is a "public service company," an "electrical company," and "gas company" as those terms are defined in RCW 80.04.010 and used in Title 80 RCW. Avista provides electric and natural gas utility service to customers in Washington.

139 (3) Avista's currently effective rates were determined by the Commission's Final Order in *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-170485, UG-170486, UE-171221, and UG-171222 *(Consolidated)*, Order 07 (Apr. 26, 2018).

140 (4) On March 29, 2019, Avista filed with the Commission tariff revisions to its currently effective Tariff WN U-28, Electric Service, in Docket UE-190222 pursuant to the Multiparty Settlement Stipulation in Docket UE-120436, subsection 10, related to the ERM rate adjustment trigger. The revisions proposed to rebate to customers approximately $34.4 million.

141 (5) On April 30, 2019, Avista filed with the Commission revisions to its currently effective Tariffs WN U-28, Electric Service, and WN U-29, Natural Gas Service, including a proposed multi-year rate plan with an initial increase in revenues of $45.8 million and $12.9 million for its electric and natural gas operations, respectively, followed by a second-year increase in revenues of $18.9 million and $6.5 million for its electric and natural gas operations, respectively.

142 (6) On November 21, 2019, the Parties filed the Settlement, which is attached to this Order as Appendix A, and requested the Commission approve and adopt it as a resolution of some, but not all, of the issues in this proceeding. Public Counsel joined the Settlement but opposed the portion of the Settlement related to Avista's natural gas revenue requirement.

143 (7) Avista initially filed testimony and exhibits supporting a natural gas revenue requirement increase of $12.9 million. Staff, Public Counsel, and AWEC filed responsive testimony and exhibits supporting natural gas revenue requirements increases of $7.0 million, $3.762 million, and $2.9 million, respectively. After adopting the Settlement's cost of capital, Public Counsel's proposed natural gas revenue requirement increase is $5.081 million.

144 (8) Avista proposed pro forma capital additions that were in service by July 2019. Public Counsel did not evaluate or include any of these pro forma capital additions in its proposed increase to Avista's natural gas revenue requirement.

145 (9) There is substantial and sufficient evidence in the record supporting the Settlement's increase of $8.0 million to Avista's natural gas revenue requirement.

146 (10) The Settlement proposes reasonable resolutions, supported by the record, to the following issues: electric revenue requirement; cost of capital; electric and natural gas rate spread and rate design; ERM refund; accelerated depreciation of Colstrip production plant to 2025; depreciation of Colstrip transmission assets; D&R costs for Colstrip Units 3 and 4; recovery for Colstrip production plant depreciation expense, transmission, and D&R; Colstrip account balances and depreciation/amortization expense; low-income weatherization funding; LIRAP funding; disconnection reduction plan; on-bill repayment/financing program; deferral amortizations; renewables to benefit low-income customers; transportation electrification; natural gas special contracts; the Inland Empire Paper special contract; Colstrip capital investment limitations; Colstrip transmission planning; and, the Colstrip community transition fund.

147 (11) Issues not addressed by the Settlement include Avista's decoupling mechanisms and proposed modifications. These proposals included contested modifications, such as: Public Counsel's request that the Commission clarify the purpose of decoupling and modify the existing mechanisms to an LRAM or a rate class decoupling mechanism; Avista's proposal to exclude new customers from the decoupling mechanism; and, NWEC's proposal for flexible conservation targets. It also included uncontested modifications, such as: continuation of the mechanisms until March 31, 2025; changing the mechanisms' 30-year moving average of weather data to a 20-year moving average; a requested exemption from natural gas decoupling reporting within 45 days after the end of each quarter; moving the effective date of annual decoupling tariff revisions; and, modifying the annualized true-up.

148 (12) The record establishes that Avista's decoupling mechanisms are working as intended. The Peach Report, conducted by an independent third-party evaluator chosen with input from the EEAG, concluded that the decoupling mechanisms have stabilized revenue without impacting utility operations and energy efficiency programs and without any adverse impacts to any customer groups.

149 (13) The evidence in the record supports a finding that Avista's mechanisms should be continued, with the requirement of a third-party evaluator after three years, without modifying the mechanisms to an LRAM or a rate class mechanism as proposed by Public Counsel.

150 (14) Avista proposes to exclude new customers from its decoupling mechanisms until they are incorporated by a subsequent rate case. Avista's proposal is unopposed, supported by the record, and, with the requirement that Avista include a status report regarding the exclusion of new customers from its decoupling mechanism, reasonable.

151 (15) Avista commits to a 5 percent additional conservation target for each its electric and natural gas mechanism. Avista's commitment for its natural gas decoupling mechanism is consistent with the commitment for its electric decoupling mechanism. Avista's proposal is reasonable and well supported by the record.

152 (16) NWEC's proposal, to create a combined 10 percent conservation target for Avista's electric and natural gas mechanisms, weakens the connection between Avista's natural gas conservation efforts and its natural gas decoupling mechanism, and also results in inter-business subsidization that has not been sufficiently justified in this proceeding.

153 (17) NWEC's proposal to adopt a 20-year moving average of weather data would have a much broader effect on Commission regulation, beyond Avista's decoupling mechanisms, and, as such, is not adequately supported by the record in this case. The record is adequate to support NWEC's proposal that Avista maintain and present data for 30-, 20-, 15-, and 10-year moving averages of weather data for purposes of decoupling.

154 (18) Avista requested exemption from WAC 480-90-275 for its natural gas decoupling reporting, which requires Avista to file its report within 45 days of the end of each quarter, and to be permitted, instead, to file its natural gas decoupling report on time with its electric decoupling report, which must be filed within 60 days of the end of each quarter.

155 (19) Moving the decoupling tariff effective date from November 1 to August 1, which is unopposed by any party, will better allow Avista to report expected earnings according to GAAP rules, recover revenues within two years of the deferral period, and align decoupling tariff revisions with Avista's annual demand side management rate filings.

156 (20) Modifying Avista's decoupling mechanism annual true-up to include a comparison of the annual decoupled revenue per customer to the actual deferred revenue, which is unopposed by any party, is reasonable and well supported by the record.

157 (21) The Settlement does not address ERM issues relating to bias in power costs calculations and the power cost workshops, carrying charge on ERM deferral balance, and remand deferral amounts related to baseline power costs.

158 (22) Avista and the Parties are engaged in power cost workshops to resolve concerns including bias in power cost calculations. The record supports that these power cost workshops are progressing well, and that it is therefore unnecessary for the Commission to reassert any declaration of bias already asserted in Avista's 2017 rate case.

159 (23) AWEC withdrew its opposition to Avista's calculation of the carrying charge for the ERM.

160 (24) Avista's calculation of the carrying charge on the ERM deferral balance, which is unopposed by any party, is reasonable and well supported by the record.

161 (25) The remand deferral amounts related to baseline power costs, as raised by AWEC, is resolved by Order 11 in Dockets UE-150204 and UG-150205 *(Consolidated)*.

162 (26) Order 11 in Dockets UE-150204 and UG-150205 *(Consolidated)* ordered Avista to return $4,919,000 to electric customers and $3,571,000 to natural gas customers. Order 11 in Dockets UE-150204 and UG-150205 *(Consolidated)* also indicated the Commission would determine in this Order how Avista must return those amounts to customers.

163 (27) Avista must return $4,919,000 to electric customers and $3,571,000 to natural gas customers over the course of one year through a separate tariff to allow for tracking and transparency.

164 (28) Due to the 2018 Colstrip outage, Avista incurred an additional $3,274,000 in replacement power costs and failed to prove that these costs were prudently incurred. The Commission determined in Order 05 of Docket UE-190882 that this approximately $3.3 million cannot be recovered from Avista's Washington ratepayers.

165 (29) In accordance with the Settlement, the ERM deferral balance is calculated by incorporating the $3.3 million disallowance in Docket UE-190882 with the estimated balance of approximately $35.8 million and will be returned to customers over two years.

166 (30) On February 29, 2020, the Governor issued a Declaration of Emergency, noting the health and economic impacts to Washington citizens resulting from the outbreak of COVID-19. Under these circumstances, it is fair, just, and reasonable and in the public interest to return a greater portion of the ERM deferral balance in the first of the two-year return period to achieve a net zero impact to Avista's electric revenue requirement beginning April 1, 2020.

167 (31) Avista's currently effective electric and natural gas rates do not provide sufficient revenue to recover the costs of its operations and provide a rate of return adequate to compensate investors at a level commensurate to what they might expect to earn on other investments bearing similar risks.

CONCLUSIONS OF LAW

Having discussed above all matters material to this decision, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

168 (1) The Commission has jurisdiction over the subject matter of, and parties to, this proceeding.

169 (2) Avista is an electric company, a natural gas company, and a public service company subject to Commission jurisdiction

170 (3) At any hearing involving a proposed change in a tariff schedule the effect of which would be to increase any rate, charge, rental, or toll theretofore charged, the burden of proof to show that such increase is just and reasonable will be upon the public service company. RCW 80.04.130 (4). The Commission's determination of whether the Company has carried its burden is adjudged based on the full evidentiary record.

171 (4) Avista's existing rates for electric and natural gas service are neither fair, just, and reasonable, nor sufficient, and should be adjusted prospectively after the date of this Order.

172 (5) Public Counsel's proposed increase to Avista's natural gas revenue requirement of $5.081 million is insufficient and, based on the evidence in the record, will not result in rates that are fair, just, reasonable, and sufficient.

173 (6) Based on the record evidence, we conclude the $8.0 million increase in natural gas revenue requirement agreed to in the Settlement is fair, just, reasonable, and sufficient.

174 (7) The Commission should approve the Settlement in this proceeding because it is lawful, supported by an appropriate record, consistent with the public interest in light of all the information available to the Commission, and sets rates that are fair, just, reasonable, and sufficient. The Settlement should be incorporated by reference into the body of this Order, as if set forth in full.

175 (8) Avista should be authorized and required to make compliance filings in these consolidated dockets in accordance with the Settlement and to recover in prospective rates its revenue deficiency of $28.5 million for electric operations and to recover in prospective rates its revenue deficiency of $8.0 million for natural gas operations.

176 (9) We conclude that continuing Avista's decoupling mechanisms until March 31, 2025, with a third-party evaluation after three years as described in this Order, is fair, just, reasonable, and in the public interest.

177 (10) Avista's proposal to exclude new customers from its decoupling mechanisms should be approved with the requirement that Avista include a status report in its yearly decoupling report regarding how many new customers are excluded from the decoupling mechanisms and their associated costs and revenues.

178 (11) Separate 5 percent conservation targets, as proposed by Avista, for each of the electric and natural gas decoupling mechanisms are fair, reasonable, and in the public interest.

179 (12) Moving the decoupling tariff effective date from November 1 to August 1 is fair to customers and to Avista and should be approved.

180 (13) Avista's proposal to modify its decoupling mechanism annual true-up to add a comparison of the annual decoupled revenue per customer to the actual deferred revenue is fair and reasonable.

181 (14) We conclude that Avista's request for an exemption from WAC 480-90-275, for purposes of its natural gas decoupling mechanism report, is consistent with the public interest, the purposes underlying regulation, and applicable statutes. Avista's request for an exemption from WAC 480-90-275, as it applies to the filing of Avista's natural gas decoupling report, should be granted.

182 (15) The Commission should continue its support for the power costs workshop process and, to stay apprised of the progress made by the Parties, should require Avista to provide a status report within three months of the date of this Order regarding the agreed-upon power supply modeling consultant, E3, and its development of a study.

183 (16) Avista should be authorized and required to make a compliance filing in these consolidated dockets to return $4,919,000 to electric customers and $3,571,000 to natural gas customers over the course of one year through a separate tariff.

184 (17) Avista should be authorized and required to make a compliance filing in these consolidated dockets to return to electric ratepayers the ERM deferral balance, incorporating the $3.3 million disallowance from Docket UE-190882 with the estimated balance of approximately $35.8 million, over two years, with a greater portion returning to ratepayers in the first year such that there is a net zero impact to Avista's electric revenue requirement beginning April 1, 2020.

185 (18) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, filings that comply with the requirements of this Order.

186 (19) The Commission should retain jurisdiction over the subject matter and the Parties to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS:

187 (1) The proposed tariff revisions Avista Corporation, d/b/a Avista Utilities, filed in these dockets on March 29, 2019, and April 30, 2019, and suspended by prior Commission order, are rejected.

188 (2) Avista Corporation, d/b/a Avista Utilities, is authorized and required to make compliance filings in this docket including all tariff sheets that are necessary and sufficient to effectuate the terms of this Order.

189 (3) The Commission Secretary is authorized to accept by letter, with copies to all parties to this proceeding, filings that comply with the requirements of this Order.

190 (4) The Commission retains jurisdiction to effectuate the terms of this Order.

DATED at Olympia, Washington, and effective March 25, 2020.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chairman

ANN E. RENDAHL, Commissioner

JAY M. BALASBAS, Commissioner

APPENDIX A

MULTIPARTY PARTIAL SETTLEMENT STIPULATION

AVISTA DECOUPLING EVALUATION

Final Report

Hugh Peach - H. Gil Peach & Associates LLC
Mark Thompson - Forefront Economics Inc.
John Joseph - Joseph Associates, Inc.

10/01/2018

Attachment C

Vision Statement

To be a world leader in developing truthful measurement and useful results; to support development of efficient, ethical, and effective practices, sustained economically; to advance human development. To improve the quality of life during the era of climate change.

Goals Statement

- To build inclusion, diversity and social justice in support of all technical goals.
- Inclusion, diversity and social justice is the top technical goal.
- Excellence in the integration of knowledge, method, and practice
- Improvement and learning at all levels
- Contextually sound measurement, analysis, and reporting
- Anticipate and meet the needs of our clients
- Awareness of human relevance and of the ethical core of research
- To go further, to find better ways

Mission Statement

With extensive experience in North America we can provide the full range of evaluation, verification, policy, management, planning, regulatory and adaptation services – wherever and whenever there is a need.

Environmental Policy Statement

Collectively, we are at a Darwin moment. Either we move to a better model for production; work intensely to mitigate climate change; anticipate and actualize inclusive climate adaptation - or we face being edited out of history.

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Introduction

This evaluation of Avista's Decoupling Mechanisms is partly a compliance evaluation and partly a policy evaluation of Avista's decoupling as a specific rate reform (alternative form of rate making) within a specific window of time.

The structure of the evaluation is in section. Each section from Section 1 through Section 7 corresponds to a specific task (Task 1 through Task 7).

- Section 1 is a compliance evaluation: Did Avista comply with the specifics of the decoupling order?
- Section 2 is concerned with billing impacts and recovery of cost of service.
- Section 3 is focused on low-income customers and contrast between low-income and residential customers generally.
- Section 4 analyzes overall revenue effect.
- Section 5 examines fixed costs and charges for non-decoupled customers.
- Section 6 is an analysis of conservation achievement.
- Section 7 examines possible adverse impacts of decoupling.
- Section 8 is an appendix on a more extensive analysis of low-income customers.
- Section 9 is an appendix on the effects of weather.
- Section 10 covers evaluation recommendations.

We find that Avista's decoupling is working well within the specific window of time examined.

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Section 1. Fidelity Analysis

For this analysis, the evaluation objective is to complete a review of whether the deferrals and rates were calculated in accordance with the Commission order approving the mechanisms. Or, in other words, were the mechanisms administered and calculated correctly, per the Amended Petition? This first task is an assessment of compliance. Operationally, we compare the Decoupling Mechanism Development of Deferrals as submitted by Avista in 2016 for the 2015 deferral year[1], as submitted in 2017 for the 2016 deferral year, and as submitted in 2018 for the 2017 deferral year to the specification of method in Schedule 75 (75, 75A, 75B, 75C, 75D, 75E) for electric service and in Schedule 175 (175, 175A, 175B, 175C, 175D, 175E) for natural gas service. This includes the Earnings Test and the 3% Annual Increase Test.

In order to facilitate and order discussion, it will be useful to define decoupling deferral years and rate years as shown in Figure 1-1.

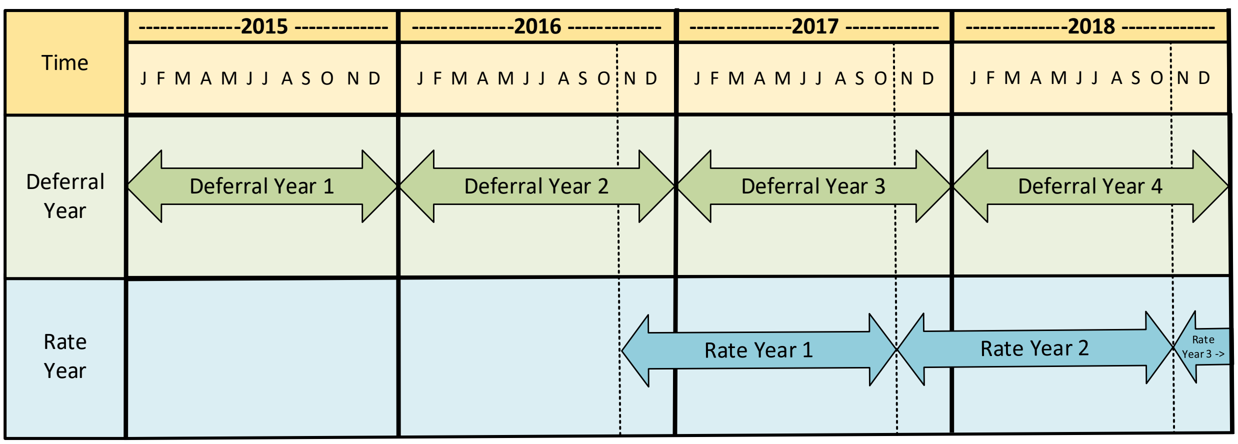


Figure 1-1. Timing of Deferral Balance Accumulation and Decoupling Rate

The timing of deferral balance accumulation and decoupling rate adjustments is shown in Figure 1-1. Avista's decoupling mechanism allows for the recovery of the difference between actual revenue and allowed revenue.[2] This difference is referred to as the decoupling deferral balance and is tracked for the two electric and two natural gas customer groups subject to decoupling; residential and non-residential.

Beginning in 2015, monthly deferrals are accumulated over a calendar year and used with other determinants to calculate the decoupling rate required to collect or refund the under or over collected revenue. Decoupling rates become effective in Schedule 75 (electric) and Schedule 175 (natural gas) November 1 of the year following the year in which deferral balances were calculated.

[1] Pat Ehrbar, Sr. Manager, Rates and Tariffs to Mr. Steven King, Executive Director and Secretary, Washington Utilities and Transportation Commission, August 31, 2016, with attachments.
[2] The details of Avista's decoupling mechanism are included in Final Order ("Order 5") for Docket Numbers UE-140188 and UG-140189.

The first deferral year resulted in a deferral balance at the end of 2015 that was used, along with other determinants, to calculate the decoupling rate in effect during the first rate year (November 1, 2016 through October 31, 2017). The same process is followed in the second deferral year and rate year. Any deferral balance carried over from the first rate year due to the application of the 3% cap is included in the calculations of decoupling rates in effect during the second rate year (November 2017 through October 2018). Each year, electric and natural gas results are separately developed. Also, within each year and energy source, Residential and Non-Residential Rate Groups are separately analyzed.

It is also useful to understand the test year in effect during each deferral year. Table 1-1 shows test year definitions used in each general rate case (GRC).

Table 1-1. General Rate Case and Test Year Definitions by Deferral Year

Item	**Electric**		**Natural Gas**	
Deferral Year	2015	2016 & 2017	2015	2016 & 2017
General Rate Case	UE-140188	UE-150204	UG-140189	UG-150205
Test Year	Proforma 2015	Oct 2013–Sep 2014	Proforma 2015	Oct 2013–Sep 2014

In the first decoupling deferral year (2015) the decoupling mechanism used a forecast of 2015 customers, usage and revenue as the test year. During the 2016 and 2017 deferral years a new GRC was in effect for electric and for natural gas, both of which used a 12-month period ending with September 2014 as the test year. This means that GRC rates and cost of service changed between the GRCs in effect for the 2015 deferral year and the GRCs in effect for the 2016 and 2017 deferral years. This has implications for some of the calculations and relationships reported in this study. For example, the determination of decoupled revenue is the same for 2016 as it for 2017 since both years use the same GRC and test year. When in our opinion the change in test year or other GRC assumptions have a meaningful influence in observed patterns or relationships being considered we will point this out to the reader.

We next examine the working of the electric decoupling mechanism and of the natural gas decoupling mechanisms in detail for the 2015 deferral year. The same detailed review is repeated for the 2016 and 2017 deferral years.

Decoupling Mechanism – 2015 Electric (Schedule 75) and Gas (Schedule 175)

Essentially, the decoupling mechanism is designed to capture all fixed cost that is to be collected from the volumetric portion of rates. With decoupling, the total amount remaining for recovery is allocated to customer bills according to a model, and recovered in a structure manner on an ongoing basis. The decoupling deferrals applied beginning in November 2016 are based on comparison of the value of actual sales in 2015 to the value of projected sales that would have met the revenue requirement from January through December 2015.

As specified in Schedule 75 and Schedule 175, calculations were carried out separately and in parallel, for Residential and Non-Residential accounts. For each of these groups of accounts, the sum of monthly deferral amounts over 2015 is the cumulative deferral (rebate or surcharge) for 2015. The cumulative deferral for 2015 is then applied over the twelve months beginning

November 2016. Amortization of the cumulative deferral balance developed over calendar 2015 was implemented over the twelve-month time window from November 1, 2016 to October 31, 2017.[3]

- For Schedule 75, Group 1 is Residential customers (Schedules 1 and 2).
- For Schedule 75, Group 2 is Non-Residential customers (Schedules 11, 12, 21, 22, 30, 31 and 32).
- For Schedule 75, two rate schedules were not decoupled (Schedule 25 – Extra Large General Service and Schedule 41-48 – Street and Area Lighting). The non-decoupled schedules are not included in this analysis.
- For Schedule 175, Group 1 is Residential customers (Schedules 101 and 102).
- For Schedule 175, Group 2 is Non-Residential customers (Schedules 111, 121 and 131.

Electric Group 1 (Residential) and Group 2 (Non-Residential)

Schedule 75A is used to develop the *Decoupled Revenue per Customer*. Schedule 75B uses the results from Schedule 75A to develop the *Monthly Decoupling Deferral*.

Schedule 75A – Decoupled Revenue per Customer

For electric service, following steps in Schedule 75A, *Decoupled Revenue per Customer (by Rate Group)* is developed. Calculation of Decoupled Revenue per Customer (by Rate Group) is specified in seven steps in Schedule 75A. These steps are implemented in Table 1-2 and Table 1-3.[4]

Step 1: Step 1 is to enter the Total Normalized Revenue, which is equal to the final approved base rate revenue approved in the Company's last general rate case, individually for each Rate Schedule. Table 1-2, Line 1 shows initial Total Normalized Net Revenue. In addition, Line 2 shows Settlement Revenue Increase. The sum of Line 1 and Line 2 is shown on Line 3 as the Total Rate Revenue (January 1, 2015). This corresponds to the full value specified in Step 1.

Step 2: Step 2 is to determine the Variable Power Supply Revenue. This value is shown on Line 6 and is the product of Normalized kWh (2015 Rate Year) from Line 4 and Retail Revenue Credit from Line 5.

Step 3: Step 3 is to enter Delivery and Power Plant Revenue. This is constructed by subtraction of Variable Power Supply Revenue (Line 6) from the Total Normalized Revenue (Line 3) and is entered on Line 7.

Step 4: Step 4 is to Remove Basic Charge Revenue. Because the decoupling mechanism only tracks revenue that varies with customer energy usage, revenue from Fixed Charges is removed.

[3] While calculation of deferral amounts begins in January 2015, customers first encountered the decoupling mechanism in customer bills November 1, 2016.

[4] Table 1-2, Table 1-3, Table 1-4, and Table 1-5 are attachments or parts of attachments to the Electric Decoupling Rate Adjustment filing of August 31, 2016.

Basic Charge Revenue is shown on Line 10. It is the product of the number of Customer Bills (2015 Rate Year) on Line 8 times the Proposed Basic Charge (Line 9).[5]

Step 5: In Step 5, the Decoupled Revenue is equal to the Delivery and Power Plant Revenue (Step 7; Line 7) minus the Basic Charge Revenue (Step 4; Line 10). Decoupled Revenue is shown on Line 11.

Step 6: In Step 6, (see Table 1-3) Decoupled Revenue is put on a per customer basis. The Decoupled Revenue (by Rate Group) is divided by the approved Rate Year number of customers (by Rate Group). This determines the annual Allowed Decoupled Revenue per Customer (by Rate Group).

Step 7: Step 7 is different from the other steps because it converts the annual Allowed Decoupled Revenue per Customer (by Rate Group) into monthly values. The assignment of monthly values is carried out by modeling monthly kWh use (by Rate Group) in relationship to the annual kWh use for the rate year. This modeling is shown in Table 1-4. Kilowatt hours (kWh) for Group 1 (Residential) for 2015 is shown in Line 3 and for Group 2 (Non-Residential) in Line 6. Both monthly values and the annual kWh value are shown. Below the monthly values (Lines 4 and 7) monthly percentages are shown. Lines 11 and 14 shows the use of these percentages, applied to annual Allowed Decoupled Revenue per Customer (by Rate Group) to generate monthly values.

The monthly values developed following the steps in Schedule 75A are then taken forward to be used in the implementation of Schedule 75B.

[5] Basic charge includes minimum charge revenue for non-residential

Table 1-2. 2015 Development of Electric Decoupled Revenue per Customer

Avista Utilities
Electric Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Electric

Updated to reflect November 2014 Power Supply update.

		TOTAL	RESIDENTIAL SCHEDULE 1	GENERAL SVC. SCH. 11,12	LG. GEN. SVC. SCH. 21,22	PUMPING SCH. 30, 31, 32	EX LG GEN SVC SCHEDULE 25	ST & AREA LTG SCH. 41-48
1	Total Normalized 2015 Revenue (Appendix 2)	$ 490,833,000	$ 214,476,000	$ 69,493,000	$ 127,831,000	$ 10,525,000	$ 61,637,000	$ 6,871,000
2	Settlement Revenue Increase (Appendix 2)	$ 12,295,000	$ 5,372,000	$ 1,738,000	$ 3,205,000	$ 264,000	$ 1,544,000	$ 172,000
3	Total Rate Revenue (January 1, 2015)	$ 503,128,000	$ 219,848,000	$ 71,231,000	$ 131,036,000	$ 10,789,000	$ 63,181,000	$ 7,043,000
4	Normalized kWhs (2015 Rate Year)	5,689,806,234	2,437,508,068	586,109,432	1,436,806,481	127,927,573	1,076,126,636	25,328,044
5	Retail Revenue Credit (line 14)	$ 0.02108	$ 0.02108	$ 0.02108	$ 0.02108	$ 0.02108	$ 0.02108	$ 0.02108
6	Variable Power Supply Revenue (L4 * L5)	$ 119,941,115	$ 51,382,670	$ 12,355,187	$ 30,287,881	$ 2,696,713	$ 22,684,749	$ 533,915
7	Delivery & Power Plant Revenue (L3 - L6)	$ 336,181,549	$ 168,465,330	$ 58,875,813	$ 100,748,119	$ 8,092,287	Schedule 25 & Schedules 41-48 Excluded From Decoupling	
8	Customer Bills (2015 Rate Year)	2,917,521	2,494,197	369,788	24,074	29,462		
9	Proposed Basic Charges		$ 8.50	$ 18.00	$ 500.00	$ 18.00		
10	Basic Charge Revenue (Ln 8 * Ln 9)	$ 40,424,175	$ 21,200,675	$ 6,656,184	$ 12,037,000	$ 530,316		
11	Decoupled Revenue	$ 295,757,375	$ 147,264,655	$ 52,219,629	$ 88,711,119	$ 7,561,971		

Table 1-3. 2015 Electric Decoupled Revenue per Customer

Updated to reflect November 2014 Power Supply update.

Avista Utilities
Electric Decoupling Mechanism
Development of Annual Decoupled Revenue Per Customer - Electric

Line No.		Source	Residential	Non-Residential Schedules*
	(a)	(b)	(c)	(d)
1	Decoupled Revenues	Appendix 4, Page 1	$ 147,264,655	$ 148,492,719
2	Rate Year # of Customers 2015	Revenue Data	207,850	35,277
3	Decoupled Revenue per Customer	(1) / (2)	$ 708.51	$ 4,209.34
	* Schedules 11, 12, 21, 22, 31, 32.			
	Revenues			
	From revenue per customer		$ 147,263,626	$ 148,492,887
	From basic charge		$ 21,200,675	$ 19,223,500
	From power supply		$ 51,382,670	$ 45,339,781
	Total		$ 219,846,971	$ 213,056,168

Table 1-4. 2015 Development of Monthly Electric Decoupled Revenue per Customer

Avista Utilities
Electric Decoupling Mechanism
Development of Monthly Decoupled Revenue Per Customer - Electric

Updated to reflect November 2014 Power Supply update.

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**Electric Sales**														
2	*Residential*														
3	- Weather-Normalized kWh Sales	Monthly Rate Year	271,130,047	240,621,765	221,370,825	175,525,307	161,914,993	154,545,588	176,072,045	186,627,300	157,769,890	180,730,371	225,437,958	285,761,978	2,437,508,067
4	- % of Annual Total	% of Total	11.12%	9.87%	9.08%	7.20%	6.64%	6.34%	7.22%	7.66%	6.47%	7.41%	9.25%	11.72%	100.00%
5	*Non-Residential**														
6	- Weather-Normalized kWh Sales	Monthly Rate Year	181,922,081	170,861,843	173,030,139	157,004,730	167,947,307	175,614,812	195,632,184	207,327,409	177,370,453	177,453,044	174,351,964	192,327,521	2,150,843,487
7	- % of Annual Total	% of Total	8.46%	7.94%	8.04%	7.30%	7.81%	8.16%	9.10%	9.64%	8.25%	8.25%	8.11%	8.94%	100.00%
8	**Monthly Decoupled Revenue Per Customer ("RPC")**														
9	*Residential*														
10	- 2015 Decoupled RPC	Appendix 4, P. 2 L. 3													$ 708.51
11	- 2015 Monthly Decoupled RPC	(4) x (10)	$ 78.81	$ 69.94	$ 64.35	$ 51.02	$ 47.06	$ 44.92	$ 51.18	$ 54.25	$ 45.86	$ 52.53	$ 65.53	$ 83.06	$ 708.51
12	*Non-Residential**														
13	- 2015 Decoupled RPC	Appendix 4, P. 2 L. 3													$ 4,209.34
14	- 2015 Monthly Decoupled RPC	(7) x (13)	$ 356.03	$ 334.39	$ 338.63	$ 307.27	$ 328.68	$ 343.69	$ 382.86	$ 405.75	$ 347.13	$ 347.29	$ 341.22	$ 376.40	$ 4,209.34

* Schedules 11, 12, 21, 22, 31, 32.

Schedule 75B – Monthly Decoupling Deferral

Schedule 75B specifies the method for developing the *Monthly Decoupling Deferral* for electric service. The calculation of the monthly decoupling deferral for January 2015 is shown in Table 1-5 for both decoupled groups.[6] In the full version of this table (Table 1-6), the monthly decoupling deferral amounts across 2015 sum to the annual total decoupling deferral for 2015. For the electric residential group, deferred revenue for 2015 is $7,167,748. Deferred revenue in 2015 for the electric non-residential group is negative $2,373,472.

Table 1-5. 2015 Electric Deferral Calculations

Avista Utilities
Electric Decoupling Mechanism
Development of Electric Deferrals (Calendar Year 2015)

Line No.		Source		Revised Jan-15
	(a)	(b)		(c)
	Residential Group			
1	Actual Customers	Revenue System		207,224
2	Monthly Decoupled Revenue per Customer	Appendix 4, Page 3		$78.81
3	Decoupled Revenue	(1) x (2)	$	16,331,182
4	Actual Base Rate Revenue	Revenue System	$	25,101,845
5	Actual Basic Charge Revenue	Revenue System	$	1,761,404
6	Actual Usage (kWhs)	Revenue System		273,966,953
7	Retail Revenue Credit ($/kWh)	Appendix 4, Page 1	$	0.021080
8	Variable Power Supply Payments	(6) x (7)	$	5,775,223
9	Customer Decoupled Payments	(4) - (5) -(8)	$	17,565,217
	Residential Revenue Per Customer Received			$84.76
10	Deferral - Surcharge (Rebate)	(3) - (9)	$	(1,234,035)
11	Deferral - Revenue Related Expenses	Rev Conv Factor	$	56,019
		FERC Rate		3.25%
12	Interest on Deferral	Avg Balance Calc	$	(1,595)
	Monthly Residential Deferral Totals		**$**	**(1,179,611)**
13	Cumulative Residential Deferral (Rebate)/Surcharge	Σ((10) ~ (12))	$	(1,179,611)
	Non-Residential Group			
14	Actual Customers	Revenue System		35,059
15	Monthly Decoupled Revenue per Customer	Appendix 4, Page 3		$356.03
16	Decoupled Revenue	(14) x (15)	$	12,482,171
17	Actual Base Rate Revenue	Revenue System	$	16,258,940
18	Actual Basic Charge Revenue	Revenue System	$	1,590,724
19	Actual Usage (kWhs)	Revenue System		162,655,588
20	Retail Revenue Credit ($/kWh)	Appendix 4, Page 1	$	0.021080
21	Variable Power Supply Payments	(19) x (20)	$	3,428,780
22	Customer Decoupled Payments	(17) - (18) -(21)	$	11,239,437
	Non-Residential Revenue Per Customer Received			$320.59
23	Deferral - Surcharge (Rebate)	(16) - (22)	$	1,242,735
24	Deferral - Revenue Related Expenses	Rev Conv Factor	$	(56,414)
		FERC Rate		3.25%
25	Interest on Deferral	Avg Balance Calc	$	1,606
	Monthly Non-Residential Deferral Totals		**$**	**1,187,927**
26	Cumulative Non-Residential Deferral (Rebate)/Surcharge	Σ((23) ~ (25))	$	1,187,927
25	Total Cumulative Deferral	(13) + (26)	$	8,316

[6] Only one month is shown here to keep the table readable on the page.

The sequence of the line numbers in Table 1-5 implement Schedule 75B. Actual customers each month (Step1 of Schedule 75B) corresponds to Line 1 for the residential group and Line 14 for the non-residential group.

Decoupling Deferrals (Step 2 of Schedule 75B) corresponds to Line 3 in both tables. It is calculated by multiplying the number of Actual Customers (Line 1) by the Monthly Decoupled Revenue per Customer (Line 2). Actual Revenue collected in a month (Step 3 of Schedule 75B) is shown on Line 4.

The Actual Basic Charge Revenue (Step 4) is shown on Line 5. The total revenue collected related to the variable power supply (Step 5) is shown on Line 8. This is the product of Actual kWh Sales (Line 6) and the Retail Revenue Credit (Line 7).

Actual Decoupled Revenue (Step 6) is calculated by subtracting the Actual Basic Charge Revenue (Line 4) and the variable power supply revenue (Line 8) from the Actual Base Rate Revenue and is shown on Line 9.

The Monthly Residential Deferral Total for each month (Step 7) is shown just below Line 12. This is the difference between the Actual Decoupled Revenue (Step 6; Line 9) and the Allowed Decoupled Revenue (Step 2; Line 3) plus any interest on the deferral.

Interest on the deferred balance accrues at the quarterly rate published by the FERC. The Monthly Residential Deferral Total for January 2015 is negative $1,179,611. In Table 1-6, these values are cumulatively incremented by month over 2015 on Line 13 and the electric deferred revenue for 2015 shown on Line 13 at the right is $7,167,748. This is the Residential value given by Avista on page 2 of 5 in the Electric Decoupling Rate Adjustment filing in compliance with Commission Order No. 05 in Docket No. UE-140188 on August 31, 2016.

Continuing with the electric analysis, identical procedural steps were applied for non-residential customers beginning in Line 14 and yielding a non-residential annual deferral amount of negative $2,373,472 in Line 26. The net deferral of $4,794,276, including electric residential and electric non-residential, is shown at the bottom of Table 1-6.

Table 1-6. 2015 Development of Electric Deferral

Electric Decoupling Mechanism

Development of Electric Deferrals (Calendar Year 2015)

Line No.		Source	Revised Jan-15	Revised Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015 Annual Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Residential Group														
1	Actual Customers	Revenue System	207,224	207,250	206,422	206,679	206,185	206,224	207,030	206,682	207,742	208,615	208,228	210,165	2,488,446
2	Monthly Decoupled Revenue per Customer	Appendix 4, Page 3	$78.81	$69.94	$64.35	$51.02	$47.06	$44.92	$51.18	$54.25	$45.86	$52.53	$65.53	$83.06	$59.08
3	Decoupled Revenue	(1) x (2)	$ 16,331,182	$ 14,495,372	$ 13,282,392	$ 10,544,743	$ 9,703,850	$ 9,263,940	$ 10,595,553	$ 11,211,862	$ 9,526,829	$ 10,959,143	$ 13,644,766	$ 17,456,805	$ 147,016,437
4	Actual Base Rate Revenue	Revenue System	$ 25,101,845	$ 17,879,887	$ 17,559,760	$ 15,694,519	$ 13,097,133	$ 14,889,107	$ 19,331,801	$ 17,006,511	$ 13,586,943	$ 13,096,810	$ 18,959,164	$ 23,830,695	
5	Actual Basic Charge Revenue	Revenue System	$ 1,761,404	$ 1,761,625	$ 1,754,587	$ 1,756,772	$ 1,752,573	$ 1,752,904	$ 1,821,150	$ 1,819,598	$ 1,819,260	$ 1,819,349	$ 1,806,884	$ 1,823,573	
6	Actual Usage (kWhs)	Revenue System	273,966,953	197,618,642	196,511,929	174,058,158	144,371,121	166,807,706	215,398,297	186,598,692	148,639,680	144,517,723	213,318,297	261,492,406	
7	Retail Revenue Credit ($/kWh)	Appendix 4, Page 1	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	
8	Variable Power Supply Payments	(6) x (7)	$ 5,775,223	$ 4,165,801	$ 4,142,471	$ 3,669,146	$ 3,043,343	$ 3,516,306	$ 4,540,596	$ 3,933,500	$ 3,133,324	$ 3,046,434	$ 4,496,750	$ 5,512,260	
9	Customer Decoupled Payments	(4) - (5) -(8)	$ 17,565,217	$ 11,952,461	$ 11,662,701	$ 10,268,602	$ 8,301,217	$ 9,619,896	$ 12,970,055	$ 11,253,413	$ 8,634,359	$ 8,231,028	$ 12,655,530	$ 16,494,862	$ 139,609,342
	Residential Revenue Per Customer Received		$84.76	$57.67	$56.50	$49.68	$40.26	$46.65	$62.65	$54.45	$41.56	$39.46	$60.78	$78.49	$56.10
10	Deferral - Surcharge (Rebate)	(3) - (9)	$ (1,234,035)	$ 2,542,911	$ 1,619,691	$ 276,142	$ 1,402,633	$ (355,956)	$ (2,374,502)	$ (41,551)	$ 892,470	$ 2,728,115	$ 989,236	$ 961,943	$ 7,407,095
11	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 56,019	$ (115,435)	$ (73,526)	$ (12,535)	$ (63,673)	$ 16,159	$ 107,791	$ 1,886	$ (40,514)	$ (123,843)	$ (44,906)	$ (43,667)	$ (336,245)
		FERC Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
12	Interest on Deferral	Avg Balance Calc	$ (1,595)	$ 92	$ 5,474	$ 7,939	$ 10,131	$ 11,511	$ 8,013	$ 4,911	$ 6,025	$ 10,721	$ 15,556	$ 18,120	$ 96,898
	Monthly Residential Deferral Totals		**$ (1,179,611)**	**$ 2,427,568**	**$ 1,551,638**	**$ 271,546**	**$ 1,349,091**	**$ (328,286)**	**$ (2,258,699)**	**$ (34,753)**	**$ 857,981**	**$ 2,614,994**	**$ 959,885**	**$ 936,395**	**$ 7,167,748**
13	Cumulative Residential Deferral (Rebate)/Surcharge	Σ((10) ~ (12))	$ (1,179,611)	$ 1,247,957	$ 2,799,595	$ 3,071,141	$ 4,420,232	$ 4,091,945	$ 1,833,247	$ 1,798,493	$ 2,656,474	$ 5,271,468	$ 6,231,353	$ 7,167,748	
	Non-Residential Group														
14	Actual Customers	Revenue System	35,059	35,579	35,140	35,293	35,221	35,212	35,004	35,238	35,232	35,284	35,077	35,843	423,182
15	Monthly Decoupled Revenue per Customer	Appendix 4, Page 3	$356.03	$334.39	$338.63	$307.27	$328.68	$343.69	$382.86	$405.75	$347.13	$347.29	$341.22	$376.40	$350.78
16	Decoupled Revenue	(14) x (15)	$ 12,482,171	$ 11,897,180	$ 11,899,500	$ 10,844,425	$ 11,576,571	$ 12,101,997	$ 13,401,801	$ 14,297,930	$ 12,229,924	$ 12,253,678	$ 11,968,907	$ 13,491,213	$ 148,445,296
17	Actual Base Rate Revenue	Revenue System	$ 16,258,940	$ 17,169,122	$ 17,145,797	$ 17,146,414	$ 17,228,784	$ 20,052,822	$ 19,981,392	$ 20,610,294	$ 17,559,914	$ 17,606,688	$ 18,027,728	$ 17,364,216	
18	Actual Basic Charge Revenue	Revenue System	$ 1,590,724	$ 1,612,616	$ 1,612,908	$ 1,601,684	$ 1,610,510	$ 1,601,190	$ 1,620,119	$ 1,617,035	$ 1,618,291	$ 1,611,788	$ 1,595,841	$ 1,623,807	
19	Acutal Usage (kWhs)	Revenue System	162,655,588	168,483,376	171,828,336	170,229,514	173,532,298	208,221,126	205,625,075	213,909,780	176,781,649	176,161,200	180,918,565	171,400,749	
20	Retail Revenue Credit ($/kWh)	Appendix 4, Page 1	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	$ 0.021080	
21	Variable Power Supply Payments	(19) x (20)	$ 3,428,780	$ 3,551,630	$ 3,622,141	$ 3,588,438	$ 3,658,061	$ 4,389,301	$ 4,334,577	$ 4,509,218	$ 3,726,557	$ 3,713,478	$ 3,813,763	$ 3,613,128	
22	Customer Decoupled Payments	(17) - (18) -(21)	$ 11,239,437	$ 12,004,877	$ 11,910,747	$ 11,956,292	$ 11,960,214	$ 14,062,331	$ 14,026,697	$ 14,484,040	$ 12,215,066	$ 12,281,422	$ 12,618,124	$ 12,127,281	$ 150,886,527
	Non-Residential Revenue Per Customer Received		$320.59	$337.41	$338.95	$338.77	$339.58	$399.36	$400.72	$411.03	$346.70	$348.07	$359.73	$338.34	$356.55
23	Deferral - Surcharge (Rebate)	(16) - (22)	$ 1,242,735	$ (107,697)	$ (11,247)	$ (1,111,868)	$ (383,643)	$ (1,960,334)	$ (624,895)	$ (186,110)	$ 14,858	$ (27,744)	$ (649,217)	$ 1,363,932	$ (2,441,231)
24	Deferral - Revenue Related Expenses	Rev Conv Factor	$ (56,414)	$ 4,889	$ 511	$ 50,473	$ 17,415	$ 88,989	$ 28,367	$ 8,448	$ (674)	$ 1,259	$ 29,471	$ (61,916)	$ 110,820
		FERC Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
25	Interest on Deferral	Avg Balance Calc	$ 1,606	$ 3,078	$ 2,933	$ 1,489	$ (440)	$ (3,472)	$ (6,823)	$ (7,890)	$ (8,133)	$ (8,171)	$ (9,069)	$ (8,169)	$ (43,061)
	Monthly Non-Residential Deferral Totals		**$ 1,187,927**	**$ (99,730)**	**$ (7,804)**	**$ (1,059,906)**	**$ (366,668)**	**$ (1,874,816)**	**$ (603,351)**	**$ (185,552)**	**$ 6,051**	**$ (34,656)**	**$ (628,814)**	**$ 1,293,847**	**$ (2,373,472)**
26	Cumulative Non-Residential Deferral (Rebate)/Surcharge	Σ((23) ~ (25))	$ 1,187,927	$ 1,088,197	$ 1,080,393	$ 20,488	$ (346,180)	$ (2,220,996)	$ (2,824,348)	$ (3,009,899)	$ (3,003,848)	$ (3,038,504)	$ (3,667,319)	$ (2,373,472)	
25	Total Cumulative Electric Deferral	(13) + (26)	$ 8,316	$ 2,336,154	$ 3,879,988	$ 3,091,628	$ 4,074,051	$ 1,870,949	$ (991,101)	$ (1,211,406)	$ (347,374)	$ 2,232,963	$ 2,564,034	$ 4,794,276	

Natural Gas Group 1 (Residential) and Group 2 (Non-Residential)

For natural gas, following steps in Schedule 175A, *Decoupled Revenue per Customer (by Rate Group)* is developed. Calculation of Decoupled Revenue per Customer (by Rate Group) is specified in seven steps in Schedule 175A. These steps are implemented in Table 1-7 and Table 1-8.[7] Monthly Decoupled Revenue per Customer for Group 1: Residential and Group 2: Non-Residential are then used to develop the *Monthly Decoupling Deferral* for natural gas, following the steps in Schedule 175B.

Schedule 175A – Decoupled Revenue per Customer

Step 1: Step 1 is to enter the Total Normalized Revenue, which is equal to the final approved base rate revenue approved in the Company's last general rate case, individually for each Rate Schedule. Table 1-7, Line 1 shows initial Total Normalized Net Revenue. In addition, Line 2 shows Settlement Revenue Increase. The sum of Line 1 and Line 2 is shown on Line 3 as the Total Rate Revenue (January 1, 2015). This corresponds to the full value specified in Step 1.

Step 2: Step 2 is to determine the Variable Gas Supply Revenue. This Variable Gas Supply Revenue is shown on Line 6. It is the product of Normalized Therms by rate schedule from the last approved general rate case (2015 Rate Year) from Line 4 times the PGA Rates from Line 5.

Step 3: Step 3 is to determine Delivery Revenue, which is entered on Line 7. To determine the Delivery Revenue, the Variable Gas Supply Revenue is subtracted from the Total Normalized Revenue.

Step 4: Step 4 is to calculate the Basic Charge Revenue. Because the decoupling mechanism only tracks revenue that varies with customer energy usage, revenue from Fixed Charges is removed. Basic Charge Revenue is the product of the number of Customer Bills in the test period (2015 Rate Year) on Line 8 times the Settlement Basic Charges (Line 9). The result, Basic Charge Revenue, is shown on Line 10.[8]

Step 5: Determine the Allowed Decoupled Revenue. The Allowed Decoupled Revenue is equal to the Delivery Revenue (from Line 7) minus the Basic Charge Revenue (Line 10). The resulting Decoupled Revenue is shown on Line 11.

Step 6: In Step 6, Decoupled Revenue from Line 11 is put on a per customer basis. The Decoupled Revenue (by Rate Group) is divided by the approved Rate Year number of customers (by Rate Group). This determines the annual Allowed Decoupled Revenue per Customer (by Rate Group) as shown in Table 1-8.

Step 7: Step 7 is different from the other steps because it converts the annual Allowed Decoupled Revenue per Customer (by Rate Group) into monthly values. The assignment of monthly values is carried out by modeling monthly therm use (by Rate Group) in relationship to the annual therm use for the rate year. This modeling is shown in Table 1-9.

[7] All tables in this section are attachments or parts of attachments to the Electric and Natural Gas Decoupling Rate Adjustment filings of August 31, 2016.
[8] For natural gas minimum charges are treated like fixed charges.

In Table 1-9, therm use for Group 1 (Residential) for 2015 is shown in Line 4 and for Group 2 (Non-Residential) in Line 8. Both monthly therm values and the annual therm values are shown. Below the monthly values, percentages (Lines 5 and 9) are shown. Lines 14 and 18 show the use of these percentages, applied to annual Allowed Decoupled Revenue per Customer (by Rate Group) to generate monthly values.

These monthly values are then taken forward to be used in the implementation of Schedule 175B.

Table 1-7. 2015 Development of Natural Gas Decoupled Revenue per Customer

Avista Utilities
Natural Gas Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Natural Gas

	TOTAL	RESIDENTIAL SCHEDULE 101	GENERAL SVC. SCH. 111	LG. GEN. SVC. SCH. 121	INTERRUPTIBLE SCH 131	SCHEDULES 112, 122, 132	SCHEDULES 146 & 148
1 Total Normalized 2015 Revenue (Appendix 2)	$ 153,075,000	$ 110,008,000	$ 34,391,000	$ 3,645,000	$ -	$ 1,055,000	$ 3,976,000
2 Settlement Revenue Increase (Appendix 2)	$ 8,500,000	$ 6,581,000	$ 1,515,000	$ 168,000	$ -	$ 56,000	$ 180,000
3 Total Rate Revenue (January 1, 2015)	$ 161,575,000	$ 116,589,000	$ 35,906,000	$ 3,813,000	$ -	$ 1,111,000	$ 4,156,000
4 Normalized Therms (2015 Rate Year)	247,662,972	117,011,207	46,256,893	5,507,204	-	1,721,574	77,166,094
5 PGA Rates		$ 0.49803	$ 0.49535	$ 0.47449	$ 0.44955		
6 Variable Gas Supply Revenue	$ 83,801,557	$ 58,275,091	$ 22,913,352	$ 2,613,113	$ -		
7 Delivery Revenue (Ln 3 - Ln 6)	$ 72,506,443	$ 58,313,909	$ 12,992,648	$ 1,199,887	$ -		
8 Customer Bills (2015 Rate Year)	1,833,425	1,802,235	30,276	305	0	48	561
9 Settlement Basic Charges		$9.00	$87.04	$215.24	$0.00		
10 Basic Charge Revenue (Ln 8 * Ln 9)	$ 18,920,986	$ 16,220,115	$ 2,635,223	$ 65,648	$ -		
11 Decoupled Revenue	$ 53,585,457	$ 42,093,794	$ 10,357,425	$ 1,134,239	$ -	Excluded From Decoupling	

Table 1-8. 2015 Natural Gas Decoupled Revenue per Customer

Avista Utilities
Natural Gas Decoupling Mechanism
Development of Decoupled Revenue Per Customer - Natural Gas

Line No.		Source	Residential	Non-Residential Schedules*
	(a)	(b)	(c)	(d)
1	Decoupled Revenues	Appendix 5, Page 1	$ 42,093,794	$ 11,491,664
2	Rate Year # of Customers 2015	Revenue Data	150,186	2,548
3	Decoupled Revenue Per Customer	(1) / (2)	$ 280.28	$ 4,509.33
	*Sales Schedules 111, 121, 131.			
		Revenues		
		From Revenue Per Customer	$ 42,094,202	$ 11,491,652
		From Basic Charges	$ 16,220,115	$ 2,700,871
		From Gas Supply	$ 58,275,091	$ 25,526,465
		Total	$ 116,589,409	$ 39,718,988

Table 1-9. 2015 Development of Monthly Natural Gas Decoupled Revenue per Customer

Avista Utilities
Natural Gas Decoupling Mechanism
'Development of Monthly Decoupled Revenue Per Customer - Natural Gas

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1															
2	**Natural Gas Delivery Volume**														
3	*Residential*														
4	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	20,096,515	16,729,826	14,285,474	9,202,394	5,127,082	3,376,941	2,456,171	2,227,453	2,907,962	6,931,034	13,836,643	19,833,713	117,011,207
5	- % of Annual Total	% of Total	17.17%	14.30%	12.21%	7.86%	4.38%	2.89%	2.10%	1.90%	2.49%	5.92%	11.83%	16.95%	100.00%
6															
7	*Non-Residential Sales**														
8	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	7,372,432	6,284,928	5,638,128	3,840,835	2,388,634	1,911,614	1,631,753	1,792,654	2,433,461	4,483,160	6,399,826	7,586,671	51,764,097
9	- % of Annual Total	% of Total	14.24%	12.14%	10.89%	7.42%	4.61%	3.69%	3.15%	3.46%	4.70%	8.66%	12.36%	14.66%	100.00%
10															
11	**Monthly Decoupled Revenue Per Customer ("RPC")**														
12	*Residential*														
13	- 2015 Decoupled RPC	Appendix 5, P. 2 L. 3													$ 280.28
14	- 2015 Monthly Decoupled RPC	(5) x (13)	$ 48.14	$ 40.07	$ 34.22	$ 22.04	$ 12.28	$ 8.09	$ 5.88	$ 5.34	$ 6.97	$ 16.60	$ 33.14	$ 47.51	$ 280.28
15															
16	*Non-Residential Sales**														
17	- 2015 Decoupled RPC	Appendix 5, P. 2 L. 3													$ 4,509.33
18	- 2015 Monthly Decoupled RPC	(9) x (17)	$ 642.24	$ 547.50	$ 491.15	$ 334.59	$ 208.08	$ 166.53	$ 142.15	$ 156.16	$ 211.99	$ 390.54	$ 557.51	$ 660.90	$ 4,509.33
19															
20	*Sales Schedules 111, 121, 131.														

Schedule 175B - Monthly Decoupling Deferral

Schedule 175B specifies the method for developing the *Monthly Decoupling Deferral* for natural gas service. The calculation of the monthly decoupling deferral for January 2015 is shown in Table 1-10.[9] In the full version of this table (Table 1-11), the monthly decoupling deferral amounts across 2015 sum to the annual total decoupling deferral for 2015. As shown in Table 1-11, the annual total decoupling deferral for Residential natural gas is $5,311,558. The annual total decoupling deferral for Non-Residential natural gas is $1,736,736.

Table 1-10. 2015 Natural Gas Deferral Calculations

Line No.	Category	Source	Revised Jan-15
	(a)	(b)	(c)
	Residential Group		
1	Actual Customers	Revenue System	150,806
2	Monthly Decoupled Revenue per Customer	Appendix 5, Page 3	$48.14
3	Decoupled Revenue	(1) x (2)	$ 7,259,455
	Actual Usage	Revenue System	20,316,016
4	Actual Base Rate Revenue (Excluding Gas Costs)	Revenue System	$ 9,163,509
5	Actual Fixed Charge Revenue	Revenue System	$ 1,357,254
6	Customer Decoupled Payments	(4) - (5)	$ 7,806,255
	Residential Revenue Per Customer Received		$51.76
7	Deferral - Surcharge (Rebate)	(3) - (6)	$ (546,800)
8	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 24,495
		FERC Rate	3.25%
9	Interest on Deferral	Avg Balance Calc	$ (707)
	Monthly Residential Deferral Totals		**$ (523,012)**
10	Cumulative Residential Deferral (Rebate)/Surcharge	Σ((7) ~ (9))	$ (523,012)
	Non-Residential Group		
11	Actual Customers	Revenue System	2,622
12	Monthly Decoupled Revenue per Customer	Appendix 5, Page 3	$642.24
13	Decoupled Revenue	(11) x (12)	$ 1,683,941
	Actual Usage	Revenue System	6,976,301
14	Actual Base Rate Revenue (Excluding Gas Costs)	Revenue System	$ 1,739,453
15	Actual Fixed Charge Revenue	Revenue System	$ 231,552
16	Customer Decoupled Payments	(14) - (15)	$ 1,507,901
	Non-Residential Revenue Per Customer Received		$575.10
17	Deferral - Surcharge (Rebate)	(13) - (16)	$ 176,039
18	Deferral - Revenue Related Expenses	Rev Conv Factor	$ (7,886)
		FERC Rate	3.25%
19	Interest on Deferral	Avg Balance Calc	$ 228
	Monthly Non-Residential Deferral Totals		**$ 168,381**
20	Cumulative Non-Residential Deferral (Rebate)/Surcharge	Σ((17) ~ (19))	$ 168,381
21	Total Cumulative Natural Gas Deferral	(10) + (20)	$ (354,631)

[9] Only one month is shown here to keep the table readable on the page. The full natural gas deferral table is shown in Table 1-11.

The individual steps in the Schedule 175B procedure are shown in both Table 1-10 and Table 1-11.

Step 1: Step 1 is to determine the actual number of customers each month. For Group 1: Residential, this is shown in Line 1 of Table 1-9 and Table 1-10. For Group 2: Non-Residential, this is shown in Line 11 of Table 1-11.

Step 2: Step 2 is to multiply the actual number of customers (Line 1 for Residential; Line 11 for Non-Residential) by the applicable monthly Allowed Decoupled Revenue per Customer (Line 2 for Residential; Line 12 for Non-Residential), which was developed in the Schedule 175A procedure. Allowed Decoupled Revenue for Residential is shown on Line 3. Allowed Decoupled Revenue for Non-Residential is shown on Line 13.

Step 3: Step 3 determines Actual Revenue collected. For Residential, this is shown on Line 4. For Non-Residential Actual Base Rate Revenue (Excluding Gas Costs) is shown on Line 14.

Step 4: Step 4 shows the amount of Actual Fixed Charge Revenues included in Actual Revenues. This is shown on Line 5 for Residential and on Line 15 for Non-Residential.

Step 5: In Step 5, Actual Fixed Charge Revenue (Line 5 for Residential; Line 15 for Non-Residential) is subtracted from Actual Revenue (Line 4 for Residential; Line 14 for Non-Residential). The result is shown on Line 6 for Residential and on Line 16 for Non-Residential. At this point in the calculation all fixed charges have been removed, leaving only variable charges. In Table 1-10 this is shown as both Customer Decoupled Payments in total and as Revenue per Customer received.

Step 6: In Step 6, the difference between the Actual Decoupled Revenue from Step 5 (Line 6 for Residential and Line 16 for Non-Residential) and the Allowed Decoupled Revenue from Step 2 (Line 3 for Residential and Line 13 for Non-Residential) is calculated. The resulting balance (Lines 7, 8 and 9 for Residential and Lines 17, 18 and 19 for Non-Residential) is the Deferral Total.

Within Step 6, Line 7 for Residential and Line 17 for Non-Residential is the Direct Deferral (which is either a Surcharge or a Rebate).

Revenue Related Expenses are stated on Line 8 for Residential and Line 18 for Non-Residential. Below this, the Federal Energy Regulatory Commission rate of interest (FERC Rate) is stated. Then, the result of the Average Balance Calculation is stated.

Line 9 (for Residential) and Line 19 (for Non-Residential) show the amount of Interest on Deferral. Below this, the result is the Deferral Totals.

For both Residential and Non-Residential, the Deferral Totals are positive, which would result in a surcharge.

Table 1-11. 2015 Development of Natural Gas Deferral

Avista Utilities

Natural Gas Decoupling Mechanism

Development of Natural Gas Deferrals (Calendar Year 2015)

Line No.		Source	Revised Jan-15	Revised Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015 Annual Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Residential Group														
1	Actual Customers	Revenue System	150,806	150,842	150,516	150,480	150,641	150,509	150,813	150,779	151,278	152,195	152,484	153,235	1,814,578
2	Monthly Decoupled Revenue per Customer	Appendix 5, Page 3	$48.14	$40.07	$34.22	$22.04	$12.28	$8.09	$5.88	$5.34	$6.97	$16.60	$33.14	$47.51	$23.39
3	Decoupled Revenue	(1) x (2)	$ 7,259,455	$ 6,044,750	$ 5,150,412	$ 3,316,991	$ 1,850,027	$ 1,217,448	$ 887,283	$ 804,478	$ 1,053,729	$ 2,526,755	$ 5,053,819	$ 7,279,921	$ 42,445,067
	Actual Usage	Revenue System	20,316,016	13,011,547	10,479,005	7,714,478	3,297,360	1,968,489	2,145,139	1,956,853	3,273,458	4,833,943	15,378,531	19,467,743	
4	Actual Base Rate Revenue (Excluding Gas Costs)	Revenue System	$ 9,163,509	$ 5,564,097	$ 5,529,316	$ 3,919,939	$ 2,352,553	$ 2,000,137	$ 2,133,781	$ 2,054,596	$ 2,453,090	$ 3,015,264	$ 6,697,840	$ 8,586,502	
5	Actual Fixed Charge Revenue	Revenue System	$ 1,357,254	$ 1,357,578	$ 1,354,644	$ 1,354,320	$ 1,355,769	$ 1,354,581	$ 1,386,104	$ 1,384,612	$ 1,386,467	$ 1,392,529	$ 1,390,608	$ 1,396,726	
6	Customer Decoupled Payments	(4) - (5)	$ 7,806,255	$ 4,206,519	$ 4,174,672	$ 2,565,619	$ 996,784	$ 645,556	$ 747,677	$ 669,984	$ 1,066,623	$ 1,622,735	$ 5,307,232	$ 7,189,776	$ 36,999,431
	Residential Revenue Per Customer Received		$51.76	$27.89	$27.74	$17.05	$6.62	$4.29	$4.96	$4.44	$7.05	$10.66	$34.81	$46.92	$20.39
7	Deferral - Surcharge (Rebate)	(3) - (6)	$ (546,800)	$ 1,838,231	$ 975,740	$ 751,372	$ 853,243	$ 571,893	$ 139,606	$ 134,493	$ (12,893)	$ 904,020	$ (253,413)	$ 90,145	$ 5,445,637
8	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 24,495	$ (82,347)	$ (43,710)	$ (33,659)	$ (38,223)	$ (25,619)	$ (6,254)	$ (6,025)	$ 578	$ (40,497)	$ 11,352	$ (4,038)	$ (243,948)
		FERC Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
9	Interest on Deferral	Avg Balance Calc	$ (707)	$ 961	$ 4,604	$ 6,850	$ 8,944	$ 10,812	$ 11,762	$ 12,148	$ 12,338	$ 13,524	$ 14,403	$ 14,230	$ 109,869
	Monthly Residential Deferral Totals		**$ (523,012)**	**$ 1,756,845**	**$ 936,634**	**$ 724,563**	**$ 823,965**	**$ 557,086**	**$ 145,114**	**$ 140,617**	**$ 23**	**$ 877,047**	**$ (227,659)**	**$ 100,337**	**$ 5,311,558**
10	Cumulative Residential Deferral (Rebate)/Surcharge	Σ((7) ~ (9))	$ (523,012)	$ 1,233,833	$ 2,170,467	$ 2,895,030	$ 3,718,994	$ 4,276,080	$ 4,421,193	$ 4,561,810	$ 4,561,833	$ 5,438,880	$ 5,211,221	$ 5,311,558	
	Non-Residential Group														
11	Actual Customers	Revenue System	2,622	2,634	2,688	2,640	2,654	2,647	2,647	2,642	2,653	2,650	2,644	2,687	31,808
12	Monthly Decoupled Revenue per Customer	Appendix 5, Page 3	$642.24	$547.50	$491.15	$334.59	$208.08	$166.53	$142.15	$156.16	$211.99	$390.54	$557.51	$660.90	$375.97
13	Decoupled Revenue	(11) x (12)	$ 1,683,941	$ 1,442,114	$ 1,320,224	$ 883,310	$ 552,248	$ 440,796	$ 376,263	$ 412,584	$ 562,400	$ 1,034,936	$ 1,474,053	$ 1,775,834	$ 11,958,701
	Actual Usage	Revenue System	6,976,301	6,062,129	4,366,524	3,881,256	2,151,394	1,884,766	1,570,309	1,559,112	2,190,921	2,990,095	6,044,897	6,497,733	
14	Actual Base Rate Revenue (Excluding Gas Costs)	Revenue System	$ 1,739,453	$ 1,533,381	$ 1,343,015	$ 1,101,126	$ 700,533	$ 616,648	$ 549,119	$ 547,598	$ 686,637	$ 862,126	$ 1,566,029	$ 1,733,268	
15	Actual Fixed Charge Revenue	Revenue System	$ 231,552	$ 232,468	$ 237,297	$ 233,119	$ 234,209	$ 233,600	$ 234,360	$ 233,812	$ 235,201	$ 235,529	$ 234,164	$ 237,838	
16	Customer Decoupled Payments	(14) - (15)	$ 1,507,901	$ 1,300,913	$ 1,105,719	$ 868,007	$ 466,323	$ 383,048	$ 314,759	$ 313,786	$ 451,436	$ 626,596	$ 1,331,866	$ 1,495,430	$ 10,165,785
	Non-Residential Revenue Per Customer Received		$575.10	$493.89	$411.35	$328.79	$175.71	$144.71	$118.91	$118.77	$170.16	$236.45	$503.73	$556.54	$319.60
17	Deferral - Surcharge (Rebate)	(13) - (16)	$ 176,039	$ 141,201	$ 214,505	$ 15,303	$ 85,924	$ 57,748	$ 61,504	$ 98,798	$ 110,964	$ 408,339	$ 142,187	$ 280,404	$ 1,792,916
18	Deferral - Revenue Related Expenses	Rev Conv Factor	$ (7,886)	$ (6,325)	$ (9,609)	$ (686)	$ (3,849)	$ (2,587)	$ (2,755)	$ (4,426)	$ (4,971)	$ (18,292)	$ (6,370)	$ (12,561)	$ (80,317)
		FERC Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
19	Interest on Deferral	Avg Balance Calc	$ 228	$ 639	$ 1,101	$ 1,401	$ 1,535	$ 1,725	$ 1,884	$ 2,097	$ 2,374	$ 3,052	$ 3,772	$ 4,329	$ 24,137
	Monthly Non-Residential Deferral Totals		**$ 168,381**	**$ 135,514**	**$ 205,996**	**$ 16,018**	**$ 83,611**	**$ 56,886**	**$ 60,633**	**$ 96,469**	**$ 108,367**	**$ 393,099**	**$ 139,590**	**$ 272,172**	**$ 1,736,736**
20	Cumulative Non-Residential Deferral (Rebate)/Surcharge	Σ((17) ~ (19))	$ 168,381	$ 303,895	$ 509,892	$ 525,909	$ 609,520	$ 666,406	$ 727,040	$ 823,509	$ 931,876	$ 1,324,975	$ 1,464,565	$ 1,736,736	
21	Total Cumulative Natural Gas Deferral	(10) + (20)	$ (354,631)	$ 1,537,728	$ 2,680,358	$ 3,420,939	$ 4,328,514	$ 4,942,486	$ 5,148,233	$ 5,385,319	$ 5,493,708	$ 6,763,854	$ 6,675,786	$ 7,048,294	

2015 Earnings Test

The decoupling mechanism, in Schedules 75D and 175D, provides for application of an earnings test, separately for electric and for natural gas.

Schedule 75D – Electric Earnings Test

According to Schedule 75D, the decoupling mechanism for electric is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues and various normalizing adjustments. As shown in Table 1-12, Line 3, the calculated rate of return on a normalized basis in 2015 is 7.40%. This exceeds the 7.32% allowed return established by Order 05 of Docket No. UE-140188 (Line 4). Excess Earnings (Line 6) is $1,113,401. A Conversion Factor is applied in Line 7. When the 50% Sharing is applied, the 2015 Total Earnings Test Sharing is $898,901 (Line 10).

Table 1-12. 2015 Electric and Natural Gas Earnings Tests

Line Number	2015 Commission Basis Earnings Test for Decoupling		
	Category	**Electric**	**Natural Gas**
1	Rate Base	$ 1,338,806,000	$ 272,971,000
2	Net Income	$ 99,114,000	$ 16,783,000
3	Calculated ROR	7.40%	6.15%
4	Base ROR	7.32%	7.32%
5	Excess ROR	0.08%	-1.17%
6	Excess Earnings	$ 1,113,401	$ -
7	Conversion Factor	0.619312	0.619450
8	Excess Revenue (Excess Earnings/CF)	$ 1,797,803	$ -
9	Sharing %	50%	50%
10	2015 Total Earnings Test Sharing	**$ 898,901**	**$ -**

For decoupled electric customers, the earnings test sharing amount is split between residential and non-residential customer groups in proportion to their contribution to total normalized revenue (see calculations in Table 1-13).

Table 1-13. 2015 Electric Earnings Test Sharing Adjustment

	Revenue From 2015 Normalized Loads and Customers at Present Billing Rates		
11	Residential Revenue	$ 216,224,542	49.58%
12	Non-Residential Revenue	$ 219,883,826	50.42%
13	Total Normalized Revenue	$ 436,108,368	100.00%
	Earnings Test Sharing Adjustment	Gross Revenue Adjustment	Net of Revenue Related Expenses
14	Residential	$ 445,679	$ 424,638
15	Non-Residential	$ 453,222	$ 431,824
16	Total	$ 898,901	

Schedule 175D – Natural Gas Earnings Test

According to Schedule 175D, the decoupling mechanism for natural gas is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues and various normalizing adjustments. As shown in Table 1-12, the rate of return on a normalized basis in 2015 is 6.15%. This is less than the 7.32% allowed return established by Order 05 of Docket No. UG-140189 which established the decoupled rates in effect in 2015.

Since the normalized return is less than the allowed return, the Earnings Test has no effect for Natural Gas customers for 2016.

2015 Three-Percent Annual Rate Increase Limitation

Decoupling annual rate adjustment surcharges are subject to a 3% annual rate increase limitation (there is no reciprocal limit on rebate rate adjustments). The test is to divide the *incremental* annual revenue to be collected (proposed surcharge revenue minus present surcharge revenue) by the total "normalized" revenue for the two Rate Groups for the most recent January through December.

Normalized revenue is determined by multiplying the weather-corrected usage for the period by the present rates in effect. If the incremental amount of the proposed surcharge exceeds 3%, only a 3% incremental rate increase will apply. Any remaining deferred revenue will be carried over to the following years.

Schedule 75E – Electric 3% Rate Increase Test

The Electric Incremental Surcharge Test is shown in Table 1-14. Specifications for the test limits the Residential Surcharge to 3% with the remainder deferred to the following year (Line 23). For Non-Residential customers, there is a Rebate of 1.4% (Line 24). The Residential Electric Carryover Deferred Revenue is $875,657 (Table 1-15, line 25). The Non-Residential Electric Carryover Deferred Revenue is $0.

Table 1-14. 2015 Electric 3% Incremental Surcharge Test

Line No.	3% Incremental Surcharge Test	Electric
	November 2016 - October 2017 Usage	
1	Residential	2,465,787,464
2	Non-Residential	2,154,719,740
	Proposed Decoupling Recovery Rates	
3	Residential	$0.00300
4	Non-Residential	-$0.00143
	Present Decoupling Recovery Rates	
5	Residential	$0.00000
6	Non-Residential	$0.00000
	Incremental Decoupling Recovery Rates	
7	Residential	$0.00300
8	Non-Residential	-$0.00143
9	Incremental Decoupling Recovery	$ 4,316,113
10	Residential	$ 7,397,362
11	Non-Residential	$ (3,081,249)
	Incremental Surcharge %	
12	Residential	**3.42%**
13	Non-Residential	**-1.40%**
	3% Test Adjustment (1)	
14	Residential	$ (910,626)
15	Non-Residential	$ -
	3% Test Rate Adjustment	
16	Residential	-$0.00037
17	Non-Residential	$0.00000
	Adjusted Proposed Decoupling Recovery Rates	
18	Residential	$0.00263
19	Non-Residential	-$0.00143
20	Adjusted Incremental Decoupling Recovery	3,403,772
21	Residential	6,485,021
22	Non-Residential	(3,081,249)
	Adjusted Incremental Surcharge %	
23	Residential	**3.00%**
24	Non-Residential	**-1.40%**

Notes

(1) The carryover balances will differ from the 3% adjustment amounts due to the revenue related expense gross up partially offset by additional interest on the outstanding balance during the amortization period.

Table 1-15. 2015 Residential Electric Carryover Deferred Revenue

Line No.		Ending Balance	Interest	Amortization
	Residential Electric			
	Calculate Estimated Monthly Balances through October 2017			
			3.25% Q1 2016 3.46% Q2 2016 3.50% Q3 2016	
1	Dec-15	$7,167,748		
2	Earnings Sharing Adjustment	($424,638)		
3	Adjusted December Balance	$6,743,110		
4	Jan-16	$6,761,373	$18,263	
5	Feb-16	$6,779,685	$18,312	
6	Mar-16	$6,798,046	$18,362	
7	Apr-16	$6,817,647	$19,601	
8	May-16	$6,837,305	$19,658	
9	Jun-16	$6,857,019	$19,714	
10	Jul-16	$6,877,019	$20,000	
11	Aug-16	$6,897,077	$20,058	
12	Sep-16	$6,917,193	$20,116	
13	**Oct-16**	**$6,937,368**	$20,175	
14	Nov-16	$6,391,343	$19,409	$565,435
15	Dec-16	$5,699,185	$17,606	$709,764
16	Jan-17	$5,015,346	$15,603	$699,442
17	Feb-17	$4,459,555	$13,797	$569,588
18	Mar-17	$3,902,195	$12,176	$569,537
19	Apr-17	$3,453,624	$10,712	$459,283
20	May-17	$3,044,869	$9,463	$418,217
21	Jun-17	$2,651,240	$8,295	$401,924
22	Jul-17	$2,179,058	$7,034	$479,216
23	Aug-17	$1,715,582	$5,671	$469,148
24	Sep-17	$1,330,525	$4,436	$389,493
25	**Oct-17**	**$875,657**	$3,213	$458,081
26	Total		$321,674	$6,189,127
	Summary			
27	2015 Deferred Revenue	$7,167,748		
28	Less Earnings Sharing	($424,638)		
29	Add Interest through 10/31/2017	$321,674		
30	Add Revenue Related Expense Ad	$295,894		
31	Total Requested Recovery	$7,360,678		
32	Customer Surcharge Revenue	$6,485,021		
33	Carryover Deferred Revenue	$875,657		

Schedule 175E – Natural Gas 3% Rate Increase Test

The Natural Gas Incremental Surcharge Test is shown in Table 1-16. The test limits the Residential and the Non-Residential Surcharge each to 3%. For both the Residential and the Non-Residential Groups, there is an additional revenue amount that is deferred to the following year.

Table 1-16. 2015 Natural Gas 3% Incremental Surcharge Test

	3% Incremental Surcharge Test		
Line No.			Natural Gas
	November 2016 - October 2017 Usage		
1	Residential		119,200,013
2	Non-Residential		52,601,464
	Proposed Decoupling Recovery Rates		
3	Residential		$0.04872
4	Non-Residential		$0.03613
	Present Decoupling Recovery Rates		
5	Residential		$0.00000
6	Non-Residential		$0.00000
	Incremental Decoupling Recovery Rates		
7	Residential		$0.04872
8	Non-Residential		$0.03613
9	Incremental Decoupling Recovery	$	7,707,916
10	Residential	$	5,807,425
11	Non-Residential	$	1,900,491
	Incremental Surcharge %		
12	Residential		**4.99%**
13	Non-Residential		**5.14%**
	3% Test Adjustment (1)		
14	Residential	$	(2,318,875)
15	Non-Residential	$	(791,747)
	3% Test Rate Adjustment		
16	Residential		-$0.01945
17	Non-Residential		-$0.01505
	Adjusted Proposed Decoupling Recovery Rates		
18	Residential		$0.02927
19	Non-Residential		$0.02108
20	Adjusted Incremental Decoupling Recovery		4,597,823
21	Residential		3,488,984
22	Non-Residential		1,108,839
	Adjusted Incremental Surcharge %		
23	Residential		**3.00%**
24	Non-Residential		**3.00%**
	Notes		
	(1) The carryover balances will differ from the 3% adjustment amounts due to the revenue related expense gross up partially offset by additional interest on the outstanding balance during the amortization period.		

For Residential Natural Gas, the Carryover Deferred Revenue is $2,261,112 (Table 1-17, Line 33).

Table 1-17. 2015 Residential Natural Gas Carryover Deferred Revenue

	Residential Natural Gas			
	Calculate Estimated Monthly Balances through October 2017			
Line No.		Ending Balance	Interest	Amortization
			3.25% Q1 2016 3.46% Q2 2016 3.50% Q3 2016	
1	Dec-15	$5,317,198		
2	Earnings Sharing Adjustment	$0		
3	Adjusted December Balance	$5,317,198		
4	Jan-16	$5,331,599	$14,401	
5	Feb-16	$5,346,038	$14,440	
6	Mar-16	$5,360,517	$14,479	
7	Apr-16	$5,375,974	$15,456	
8	May-16	$5,391,474	$15,501	
9	Jun-16	$5,407,020	$15,545	
10	Jul-16	$5,422,790	$15,770	
11	Aug-16	$5,438,607	$15,816	
12	Sep-16	$5,454,469	$15,863	
13	**Oct-16**	**$5,470,378**	$15,909	
14	Nov-16	$5,086,191	$15,373	$399,559
15	Dec-16	$4,521,334	$13,991	$578,847
16	Jan-17	$3,934,687	$12,314	$598,961
17	Feb-17	$3,457,978	$10,765	$487,474
18	Mar-17	$3,054,220	$9,483	$413,241
19	Apr-17	$2,815,654	$8,548	$247,114
20	May-17	$2,686,572	$8,012	$137,094
21	Jun-17	$2,615,315	$7,721	$78,978
22	Jul-17	$2,561,284	$7,538	$61,570
23	Aug-17	$2,513,130	$7,389	$55,543
24	Sep-17	$2,450,245	$7,228	$70,112
25	**Oct-17**	**$2,261,112**	$6,861	$195,994
26	Total		$268,402	$3,324,488
	Summary			
27	2015 Deferred Revenue	$5,317,198		
28	Less Earnings Sharing	$0		
29	Add Interest through 10/31/2017	$268,402		
30	Add Revenue Related Expense Adj.	$164,496		
31	Total Requested Recovery	$5,750,096		
32	Customer Surcharge Revenue	$3,488,984		
33	Carryover Deferred Revenue	$2,261,112		

For Non-Residential Natural Gas, the Carryover Deferred Revenue is $770,314 (Table 1-18, Line 33).[10]

Table 1-18. 2015 Non-Residential Natural Gas Carryover Deferred Revenue

	Non-Residential Natural Gas			
	Calculate Estimated Monthly Balance through October 2017			
Line No.		Ending Balance	Interest	Amortization
			3.25% Q1 2016 3.46% Q2 2016 3.50% Q3 2016	
1	Dec-15	$1,736,736		
2	Earnings Sharing Adjustment	$0		
3	Adjusted December Balance	$1,736,736		
4	Jan-16	$1,741,440	$4,704	
5	Feb-16	$1,746,156	$4,716	
6	Mar-16	$1,750,885	$4,729	
7	Apr-16	$1,755,934	$5,048	
8	May-16	$1,760,997	$5,063	
9	Jun-16	$1,766,074	$5,078	
10	Jul-16	$1,771,225	$5,151	
11	Aug-16	$1,776,391	$5,166	
12	Sep-16	$1,781,572	$5,181	
13	**Oct-16**	**$1,786,769**	$5,196	
14	Nov-16	$1,662,289	$5,023	$129,502
15	Dec-16	$1,508,055	$4,617	$158,850
16	Jan-17	$1,353,347	$4,167	$158,875
17	Feb-17	$1,223,770	$3,753	$133,330
18	Mar-17	$1,113,406	$3,403	$113,768
19	Apr-17	$1,042,272	$3,139	$74,273
20	May-17	$998,010	$2,971	$47,233
21	Jun-17	$965,754	$2,860	$35,116
22	Jul-17	$934,225	$2,767	$34,295
23	Aug-17	$900,960	$2,672	$35,938
24	Sep-17	$859,553	$2,564	$43,970
25	**Oct-17**	**$770,314**	$2,373	$91,613
26	Total		$90,341	$1,056,763
	Summary			
27	2015 Deferred Revenue	$1,736,736		
28	Less Earnings Sharing	$0		
29	Add Interest through 10/31/2017	$90,341		
30	Add Revenue Related Expense Adj	$52,075		
31	Total Requested Recovery	$1,879,152		
32	Customer Surcharge Revenue	$1,108,839		
33	Carryover Deferred Revenue	$770,314		

[10] The difference of $5,640 between the deferred revenue of $5,317,198 in Table 1-17 and the deferred revenue of $5,311,558 in Line 9 of Table 1-11 is the balance from a prior account associated with a previous decoupling mechanism.

Decoupling Mechanism - 2016 Electric (Schedule 75) and Natural Gas (Schedule 175)

In this section, we review analysis of data from the test year from October 2013 through September 2014 (a historical test year), which was used to develop amounts for revenue recovery for calendar 2016. Recovery occurred from November 2017 through the end of October 2018 (the second rate year). The decoupling mechanism is designed to capture all fixed cost assigned for recovery through volumetric rates that is not actually recovered due to lower sales than expected during calendar 2016. This cost is recovered by allocation to customer bills according to a model. The decoupling deferrals total is based on comparison of the value of actual sales in calendar 2016 to the value of normalized sales (from October 2013 through September 2014) on a per customer basis.

As specified in Schedule 75 and Schedule 175, calculations were carried out separately and in parallel, for Residential and Non-Residential accounts. For each of these groups of accounts, the sum of monthly deferral amounts over calendar year 2016 is the cumulative deferral (rebate or surcharge). The cumulative deferral (with adjustments for prior year carryover balance, interest, and revenue related expense adjustment) is collected through the decoupling tariff on a volumetric basis from November 1, 2017 to October 31, 2018.

Electric Group 1 (Residential) and Group 2 (Non-Residential)

First the electric service analysis is reviewed, then the analysis for natural gas service.

Schedule 75A – Decoupled Revenue per Customer

For electric service, following steps in Schedule 75A, *Decoupled Revenue per Customer (by Rate Group)* is developed. Calculation of Decoupled Revenue per Customer (by Rate Group) is specified in seven steps in Schedule 75A. These steps are implemented in Table 1-19 and Table 1-20.[11]

Step 1: Step 1 is to enter the Total Normalized Revenue, which is equal to the final approved base rate revenue approved in the Company's last general rate case, individually for each Rate Schedule. Table 1-19, Line 1 shows initial Total Normalized Net Revenue. In addition, Line 2 shows the Allowed Revenue Increase. The sum of Line 1 and Line 2 is shown on Line 3 as the Total Rate Revenue (January 11, 2016). This corresponds to the full value specified in Step 1.

Step 2: Step 2 is to determine the Variable Power Supply Revenue. This value is shown on Line 6 and is the product of Normalized kWh (12 ME September 2014 Test Year) from Line 4 and Retail Revenue Adjustment from Line 5.

Step 3: Step 3 is to enter Delivery and Power Plant Revenue. This is constructed by subtraction of Variable Power Supply Revenue (Line 6) from the Total Normalized Revenue (Line 3) and is entered on Line 7.

[11] All tables in this section are attachments or parts of attachments to the Electric and Natural Gas Decoupling Rate Adjustment filings of August 31, 2017 for the 2016 deferral year.

Step 4: Step 4 is to Remove Basic Charge Revenue. Because the decoupling mechanism only tracks revenue that varies with customer energy usage, revenue from Fixed Charges is removed. Basic Charge Revenue is shown on Line 10. Basic Charge Revenue is the product of the number of Customer Bills in the GRC test year on Line 8 times the Allowed Basic Charge (Line 9).

Step 5: In Step 5, the Decoupled Revenue is equal to the Delivery and Power Plant Revenue (Line 7) minus the Basic Charge Revenue (Line 10). Decoupled Revenue is shown on Line 11.

Step 6: In Step 6, (see Table 1-20) Decoupled Revenue is put on a per customer basis. The Decoupled Revenue (by Rate Group) is divided by the approved Test Year number of customers (by Rate Group). This determines the annual Allowed Decoupled Revenue per Customer (by Rate Group).

Step 7: Step 7 is different from the other steps because it converts the annual Allowed Decoupled Revenue per Customer (by Rate Group) into monthly values. The assignment of monthly values is carried out by modeling monthly kWh use (by Rate Group) in relationship to the annual kWh use for the rate year. This modeling is shown in Table 1-21. Kilowatt hours for Group 1 (Residential) for the test year is shown in Line 3 and for Group 2 (Non-Residential) in Line 6. Both monthly values and the annual kWh values are shown. Below the monthly values (Lines 4 and 7) monthly percentages are shown. Lines 11 and 14 use this percentage model, applied to annual Allowed Decoupled Revenue per Customer (by Rate Group), to generate monthly values.

The monthly values developed following the steps in Schedule 75A are then taken forward to be used in the implementation of Schedule 75B.

Table 1-19. 2016 Development of Electric Decoupled Revenue per Customer

Electric Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Electric

		TOTAL	RESIDENTIAL SCHEDULE 1	GENERAL SVC. SCH. 11,12	LG. GEN. SVC. SCH. 21,22	PUMPING SCH. 30, 31, 32	EX LG GEN SVC SCHEDULE 25	ST & AREA LTG SCH. 41-48
1	Total Normalized 12 ME Sept 2014 Revenue	$ 499,982,000	$ 214,841,000	$ 71,304,000	$ 130,152,000	$ 11,471,000	$ 65,194,000	$ 7,020,000
2	Allowed Revenue Increase (Attachment 1)	$ (8,110,000)	$ (3,478,000)	$ (1,159,000)	$ (2,118,000)	$ (187,000)	$ (1,056,000)	$ (112,000)
3	Total Rate Revenue (January 11, 2016)	$ 491,872,000	$ 211,363,000	$ 70,145,000	$ 128,034,000	$ 11,284,000	$ 64,138,000	$ 6,908,000
4	Normalized kWhs (12ME Sept 2014 Test Year)	5,653,834,483	2,378,478,031	588,401,236	1,419,228,271	137,227,044	1,105,372,136	25,127,765
5	Retail Revenue Adjustment (line 14)	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641
6	Variable Power Supply Revenue (L4 * L5)	$ 92,779,424	$ 39,030,824	$ 9,655,664	$ 23,289,536	$ 2,251,896	$ 18,139,157	$ 412,347
7	Delivery & Power Plant Revenue (L3 - L6)	$ 346,598,080	$ 172,332,176	$ 60,489,336	$ 104,744,464	$ 9,032,104		
8	Customer Bills (12ME Sept 2014 Test Year)	2,879,945	2,462,067	364,552	24,110	29,216		
9	Allowed Basic Charges		$ 8.50	$ 18.00	$ 500.00	$ 18.00		
10	Basic Charge Revenue (Ln 8 * Ln 9)	$ 40,070,394	$ 20,927,570	$ 6,561,936	$ 12,055,000	$ 525,888		
11	Decoupled Revenue	$ 306,527,686	$ 151,404,606	$ 53,927,400	$ 92,689,464	$ 8,506,216	Excluded From Decoupling	
12	Retail Revenue Adjustment - (Attachment 3)	$0.01566						
13	Gross Up Factor for Revenue Related Exp	104.81%						
14	Grossed Up Retail Revenue Adjustment	$0.01641						

		Residential	Non-Residential Group
15	Average Number of Customers (Line 8 / 12)	205,172	34,823
16	Annual kWh	2,378,478,031	2,144,856,551
17	Basic Charge Revenues	20,927,570	19,142,824
18	Customer Bills	2,462,067	417,878
19	Average Basic Charge	$8.50	$45.81

Table 1-20. 2016 Development of Electric Decoupled Revenue per Customer

Avista Utilities
Electric Decoupling Mechanism
Development of Annual Decoupled Revenue Per Customer - Electric

Line No.		Source	Residential	Non-Residential Schedules*
	(a)	(b)	(c)	(d)
1	Decoupled Revenues	Attachment 4, Page 1	$ 151,404,606	$ 155,123,080
2	Test Year # of Customers 12 ME 09.2014	Revenue Data	205,172	34,823
3	Decoupled Revenue per Customer	(1) / (2)	$ 737.94	$ 4,454.59
	* Schedules 11, 12, 21, 22, 31, 32.			
	Revenues			
	From revenue per customer		$ 151,404,810	$ 155,122,930
	From basic charge		$ 20,927,570	$ 19,142,824
	From power supply		$ 39,030,824	$ 35,197,096
	Total		$ 211,363,204	$ 209,462,850

Table 1-21. 2016 Development of Monthly Electric Decoupled Revenue per Customer

Avista Utilities
Electric Decoupling Mechanism
Development of Monthly Decoupled Revenue Per Customer - Electric

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**Electric Sales**														
2	*Residential*														
3	- Weather-Normalized kWh Sales	Monthly Rate Year	284,675,925	232,597,855	228,752,581	172,322,869	166,632,549	148,170,954	153,360,033	181,322,317	146,560,541	174,054,557	212,665,464	277,362,386	2,378,478,031
4	- % of Annual Total	% of Total	11.97%	9.78%	9.62%	7.25%	7.01%	6.23%	6.45%	7.62%	6.16%	7.32%	8.94%	11.66%	100.00%
5	*Non-Residential**														
6	- Weather-Normalized kWh Sales	Monthly Rate Year	174,546,983	177,500,854	166,289,029	165,417,455	178,108,889	185,503,197	200,737,081	187,588,012	179,420,897	183,203,251	168,530,619	178,010,284	2,144,856,551
7	- % of Annual Total	% of Total	8.14%	8.28%	7.75%	7.71%	8.30%	8.65%	9.36%	8.75%	8.37%	8.54%	7.86%	8.30%	100.00%
8	**Monthly Decoupled Revenue Per Customer ("RPC")**														
9	*Residential*														
10	-UE-150204 Decoupled RPC	Attachment 4, P. 2 L. 3													$ 737.94
11	- Monthly Decoupled RPC	(4) x (10)	$ 88.32	$ 72.17	$ 70.97	$ 53.46	$ 51.70	$ 45.97	$ 47.58	$ 56.26	$ 45.47	$ 54.00	$ 65.98	$ 86.05	$ 737.94
12	*Non-Residential**														
13	-UE-150204 Decoupled RPC	Attachment 4, P. 2 L. 3													$ 4,454.59
14	- Monthly Decoupled RPC	(7) x (13)	$ 362.51	$ 368.65	$ 345.36	$ 343.55	$ 369.91	$ 385.27	$ 416.90	$ 389.60	$ 372.63	$ 380.49	$ 350.02	$ 369.70	$ 4,454.59

* Schedules 11, 12, 21, 22, 31, 32.

Schedule 75B - Monthly Decoupling Deferral

Schedule 75B specifies the method for developing the *Monthly Decoupling Deferral* for electric service. For Group 1 (Residential), the calculation of the monthly decoupling deferral for January 2016 is shown in the top part of Table 1-22.[12] For Group 2 (Non-Residential) the calculation method is shown in the bottom part of Table 1-22. In the full version of this table (Table 1-23), the monthly decoupling deferral amounts across 2016 sum to the annual total decoupling deferral for 2016. For the Electric Residential, deferred revenue for 2016 is $10,288,205. For Electric Non-Residential, deferred revenue for 2016 is $1,967,777

Residential Decoupling Deferrals (Step 2 of Schedule 75B) corresponds to Line 3 in the top part of Table 1-22 and the top part of Table 1-23. It is calculated by multiplying the number of Actual Customers (Line 1) by the Monthly Decoupled Revenue per Customer (Line 2).

Residential Actual Revenue collected in a month (Step 3 of Schedule 75B) is shown on Line 4.

The Residential Actual Basic Charge Revenue (Step 4) is shown on Line 5. The total revenue collected related to the variable power supply (Step 5) is shown on Line 8. This is the product of Actual kWh Sales (Line 6) and the Retail Revenue Credit (Line 7).

Residential Actual Decoupled Revenue (Step 6) is calculated by subtracting the Actual Basic Charge Revenue (Line 4) and the variable power supply revenue (Line 8) from the Actual Base Rate Revenue and is shown on Line 9.

The Monthly Residential Deferral Total for each month (Step 7) is shown just below Line 12. This is the difference between the Actual Decoupled Revenue (Step 6; Line 9) and the Allowed Decoupled Revenue (Step 2; Line 3) plus any interest on the deferral.

Interest on the deferred balance accrues at the quarterly rate published by the FERC. In Table 1-23, these values are cumulatively incremented by month over 2016 on Line 13 and the electric deferred revenue for 2016 shown on Line 13 at the right is $10,288,205. This is the Residential value given by Avista on page 2 of 6 in the Electric Decoupling Rate Adjustment filing in compliance with Commission Order No. 05 in Docket No. UE-140188 on August 31, 2017.

For Electric Non-Residential, Schedule 75B specifies the method for developing the Monthly Decoupling Deferral for electric service. In the full version of this table (bottom section of Table 1-23), the monthly decoupling deferral amounts across 2016 sum to the annual total decoupling deferral for 2016 (for Electric Non-Residential) of $1,967,777. This is the Electric Non-Residential value given on Page 3 of 6 in the Electric Decoupling Rate Adjustment filing in compliance with Commission Order No. 05 in Docket No. UE-140188 on August 31, 2017. Since deferred revenue is positive, Electric Non-Residential receives a surcharge.

The calculations and the Excel programming are identical for Electric Residential and Electric Non-Residential.[13]

[12] Only the first few columns of the table are shown here, to keep the table readable on the page.

[13] New rates became effective January 11, 2016. Deferred revenue calculations for the first 10 days of January 2016 were calculated at the rates prior to the change. January 11th through the 31st was calculated using the new rates.

Table 1-22. 2016 Electric Deferral Calculations

Avista Utilities
Decoupling Mechanism - UE-150204 Base effective 1/11/2016
Development of WA Electric Deferrals (Calendar Year 2016)

Line No.		Source		32% Old Base		68% New Base		Pro Rated Jan-16
	(a)	(b)						(c)
	Residential Group							
1	Actual Customers	Revenue System		67,166.77		141,050.23		208,217
2	Monthly Decoupled Revenue per Customer	Attachment 4, Page 3		$78.81		$88.32		$85.25
3	Decoupled Revenue	(1) x (2)	$	5,293,368	$	12,457,946	$	17,751,313
4	Actual Base Rate Revenue	Revenue System	$	8,069,977	$	16,946,951	$	25,016,927
5	Actual Basic Charge Revenue	Revenue System	$	582,373	$	1,222,984	$	1,805,358
6	Acutal Usage (kWhs)	Revenue System		88,782,350		186,442,936		275,225,286
7	Retail Revenue Credit ($/kWh)	Attachment 4, Page 1	$	0.02108	$	0.01641	$	0.01792
8	Variable Power Supply Payments	(6) x (7)	$	1,871,532	$	3,059,529	$	4,931,061
9	Customer Decoupled Payments	(4) - (5) -(8)	$	5,616,071	$	12,664,438	$	18,280,509
	Residential Revenue Per Customer Received			$83.61		$89.79		$87.80
10	Deferral - Surcharge (Rebate)	(3) - (9)	$	(322,704)	$	(206,492)	$	(529,196)
11	Deferral - Revenue Related Expenses	Rev Conv Factor	$	14,649	$	9,474	$	24,123
		FERC Rate						3.25%
12	Interest on Deferral	Avg Balance Calc					$	(684)
	Monthly Residential Deferral Totals						**$**	**(505,757)**
13	Cumulative Residential Deferral Surcharge/(Rebate) Balance	Σ((10) ~ (12))					$	(505,757)
	Non-Residential Group							
14	Actual Customers	Revenue System		11,397.10		23,933.90		35,331
15	Monthly Decoupled Revenue per Customer	Attachment 4, Page 3		$356.03		$362.51		$360.42
16	Decoupled Revenue	(14) x (15)	$	4,057,746	$	8,676,316	$	12,734,062
17	Actual Base Rate Revenue	Revenue System	$	5,689,116	$	11,947,143	$	17,636,258
18	Actual Basic Charge Revenue	Revenue System	$	512,506	$	1,076,263	$	1,588,769
19	Acutal Usage (kWhs)	Revenue System		57,402,939		120,546,172		177,949,111
20	Retail Revenue Credit ($/kWh)	Attachment 4, Page 1	$	0.02108	$	0.01641	$	0.01792
21	Variable Power Supply Payments	(19) x (20)	$	1,210,054	$	1,978,163	$	3,188,217
22	Customer Decoupled Payments	(17) - (18) -(21)	$	3,966,555	$	8,892,717	$	12,859,272
	Non-Residential Revenue Per Customer Received			$348.03		$371.55		$363.97
23	Deferral - Surcharge (Rebate)	(16) - (22)	$	91,191	$	(216,401)	$	(125,210)
24	Deferral - Revenue Related Expenses	Rev Conv Factor	$	(4,140)	$	9,928	$	5,789
		FERC Rate						3.25%
25	Interest on Deferral	Avg Balance Calc					$	(162)
	Monthly Non-Residential Deferral Totals						**$**	**(119,583)**
26	Cumulative Non-Residential Deferral Surcharge/(Rebate) Balance	Σ((23) ~ (25))					$	(119,583)
27	**Total Cumulative Electric Deferral**	**(13) + (26)**					$	(625,340)

Table 1-23. 2016 Development of Electric Deferral

Avista Utilities
Decoupling Mechanism - UE-150204 Base effective 1/11/2016
Development of WA Electric Deferrals (Calendar Year 2016)

Line No.		Source	32% Old Base	68% New Base	Pro Rated Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
	(a)	(b)			(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Residential Group																
1	Actual Customers	Revenue System	67,166.77	141,050.23	208,217	210,418	209,750	209,405	209,004	208,965	209,204	209,512	210,314	210,674	211,346	211,562	2,518,371
2	Monthly Decoupled Revenue per Customer	Attachment 4, Page 3	$78.81	$88.32	$85.25	$72.17	$70.97	$53.46	$51.70	$45.97	$47.58	$56.26	$45.47	$54.00	$65.98	$86.05	$734.87
3	Decoupled Revenue	(1) x (2)	$ 5,293,368	$ 12,457,946	$ 17,751,313	$ 15,184,850	$ 14,886,407	$ 11,195,716	$ 10,805,288	$ 9,606,353	$ 9,954,148	$ 11,786,424	$ 9,563,286	$ 11,376,751	$ 13,944,820	$ 18,205,690	$ 154,261,045
4	Actual Base Rate Revenue	Revenue System	$ 8,069,977	$ 16,946,951	$ 25,016,927	$ 18,682,934	$ 17,505,111	$ 13,895,473	$ 12,707,668	$ 13,822,017	$ 15,745,170	$ 16,208,773	$ 13,825,250	$ 13,859,174	$ 17,109,790	$ 25,244,722	$ 203,623,009
5	Actual Basic Charge Revenue	Revenue System	$ 582,373	$ 1,222,984	$ 1,805,358	$ 1,824,049	$ 1,818,745	$ 1,824,228	$ 1,831,181	$ 1,838,974	$ 1,833,280	$ 1,848,334	$ 1,838,516	$ 1,835,029	$ 1,834,655	$ 1,836,304	$ 21,968,649
6	Actual Usage (kWhs)	Revenue System	88,782,350	186,442,936	275,225,286	209,519,142	198,506,123	156,664,757	142,430,315	156,502,975	178,634,451	181,567,778	154,183,097	157,178,161	193,299,820	284,514,826	2,288,226,731
7	Retail Revenue Credit ($/kWh)	Attachment 4, Page 1	$ 0.02108	$ 0.01641	$ 0.01792	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	
8	Variable Power Supply Payments	(6) x (7)	$ 1,871,532	$ 3,059,529	$ 4,931,061	$ 3,438,209	$ 3,257,485	$ 2,570,869	$ 2,337,281	$ 2,568,214	$ 2,931,391	$ 2,979,527	$ 2,530,145	$ 2,579,294	$ 3,172,050	$ 4,668,888	$ 37,964,414
9	Customer Decoupled Payments	(4) - (5) -(8)	$ 5,616,071	$ 12,664,438	$ 18,280,509	$ 13,420,676	$ 12,428,881	$ 9,500,377	$ 8,539,206	$ 9,414,829	$ 10,980,499	$ 11,380,912	$ 9,456,589	$ 9,444,852	$ 12,103,086	$ 18,739,530	$ 143,689,946
	Residential Revenue Per Customer Received		$83.61	$89.79	$87.80	$63.78	$59.26	$45.37	$40.86	$45.05	$52.49	$54.32	$44.96	$44.83	$57.27	$88.58	
10	Deferral - Surcharge (Rebate)	(3) - (9)	$ (322,704)	$ (206,492)	$ (529,196)	$ 1,764,174	$ 2,457,526	$ 1,695,339	$ 2,266,082	$ 191,524	$ (1,026,351)	$ 405,512	$ 106,697	$ 1,931,899	$ 1,841,734	$ (533,841)	$ 10,571,099
11	Deferral - Revenue Related Expenses	Rev Conv Factoı	$ 14,649	$ 9,474	$ 24,123	$ (80,940)	$ (112,751)	$ (77,782)	$ (103,968)	$ (8,787)	$ 47,089	$ (18,605)	$ (4,895)	$ (88,636)	$ (84,499)	$ 24,493	$ (485,159)
		FERC Rate			3.25%	3.25%	3.25%	3.46%	3.46%	3.46%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
12	Interest on Deferral	Avg Balance Calc			$ (684)	$ 910	$ 6,367	$ 12,509	$ 17,994	$ 21,426	$ 20,575	$ 19,771	$ 20,541	$ 23,438	$ 28,757	$ 30,661	$ 202,264
	Monthly Residential Deferral Totals				**$ (505,757)**	**$ 1,684,144**	**$ 2,351,141**	**$ 1,630,066**	**$ 2,180,108**	**$ 204,163**	**$ (958,687)**	**$ 406,678**	**$ 122,343**	**$ 1,866,701**	**$ 1,785,992**	**$ (478,687)**	**$ 10,288,205**
13	Cumulative Deferral (Rebate)/Surcharge Balance	Σ((10) ~ (12))			$ (505,757)	$ 1,178,387	$ 3,529,528	$ 5,159,594	$ 7,339,701	$ 7,543,864	$ 6,585,177	$ 6,991,856	$ 7,114,199	$ 8,980,900	$ 10,766,892	**$ 10,288,205**	
	Non-Residential Group																
14	Actual Customers	Revenue System	11,397.10	23,933.90	35,331	35,572	35,571	35,497	35,658	35,516	35,519	35,694	35,669	35,828	35,762	35,782	427,399
15	Monthly Decoupled Revenue per Customer	Attachment 4, Page 3	$356.03	$362.51	$360.42	$368.65	$345.36	$343.55	$369.91	$385.27	$416.90	$389.60	$372.63	$380.49	$350.02	$369.70	$4,452.50
16	Decoupled Revenue	(14) x (15)	$ 4,057,746	$ 8,676,316	$ 12,734,062	$ 13,113,488	$ 12,284,830	$ 12,195,019	$ 13,190,221	$ 13,683,114	$ 14,808,048	$ 13,906,242	$ 13,291,483	$ 13,632,177	$ 12,517,284	$ 13,228,762	$ 158,584,729
17	Actual Base Rate Revenue	Revenue System	$ 5,689,116	$ 11,947,143	$ 17,636,258	$ 16,471,105	$ 16,873,160	$ 16,097,542	$ 17,385,509	$ 18,365,177	$ 19,234,390	$ 18,762,263	$ 17,379,615	$ 17,841,080	$ 16,178,487	$ 18,917,894	$ 211,142,481
18	Actual Basic Charge Revenue	Revenue System	$ 512,506	$ 1,076,263	$ 1,588,769	$ 1,582,404	$ 1,565,686	$ 1,575,041	$ 1,566,939	$ 1,572,602	$ 1,567,372	$ 1,565,138	$ 1,570,581	$ 1,567,535	$ 1,580,197	$ 1,573,244	$ 18,875,508
19	Actual Usage (kWhs)	Revenue System	57,402,939	120,546,172	177,949,111	164,762,769	170,862,451	162,142,313	179,654,733	189,325,960	201,220,320	194,881,850	178,530,679	182,657,424	160,599,007	196,411,492	2,158,998,109
20	Retail Revenue Credit ($/kWh)	Attachment 4, Page 1	$ 0.02108	$ 0.01641	$ 0.01792	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	
21	Variable Power Supply Payments	(19) x (20)	$ 1,210,054	$ 1,978,163	$ 3,188,217	$ 2,703,757	$ 2,803,853	$ 2,660,755	$ 2,948,134	$ 3,106,839	$ 3,302,025	$ 3,198,011	$ 2,929,688	$ 2,997,408	$ 2,635,430	$ 3,223,113	$ 35,697,231
22	Customer Decoupled Payments	(17) - (18) -(21)	$ 3,966,555	$ 8,892,717	$ 12,859,272	$ 12,184,944	$ 12,503,621	$ 11,861,746	$ 12,870,436	$ 13,685,737	$ 14,364,993	$ 13,999,113	$ 12,879,346	$ 13,276,136	$ 11,962,861	$ 14,121,538	$ 156,569,743
	Non-Residential Revenue Per Customer Received		$348.03	$371.55	$363.97	$342.54	$351.51	$334.16	$360.94	$385.34	$404.43	$392.20	$361.08	$370.55	$334.51	$394.65	
23	Deferral - Surcharge (Rebate)	(16) - (22)	$ 91,191	$ (216,401)	$ (125,210)	$ 928,544	$ (218,791)	$ 333,273	$ 319,784	$ (2,623)	$ 443,056	$ (92,871)	$ 412,137	$ 356,041	$ 554,423	$ (892,776)	$ 2,014,986
24	Deferral - Revenue Related Expenses	Rev Conv Factoı	$ (4,140)	$ 9,928	$ 5,789	$ (42,602)	$ 10,038	$ (15,291)	$ (14,672)	$ 120	$ (20,327)	$ 4,261	$ (18,909)	$ (16,335)	$ (25,437)	$ 40,961	$ (92,403)
		FERC Rate			3.25%	3.25%	3.25%	3.46%	3.46%	3.46%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
25	Interest on Deferral	Avg Balance Calc			$ (162)	$ 876	$ 1,795	$ 2,074	$ 2,978	$ 3,423	$ 4,085	$ 4,585	$ 5,042	$ 6,126	$ 7,410	$ 6,961	$ 45,194
	Monthly Non-Residential Deferral Totals				**$ (119,583)**	**$ 886,818**	**$ (206,958)**	**$ 320,056**	**$ 308,091**	**$ 920**	**$ 426,814**	**$ (84,026)**	**$ 398,270**	**$ 345,832**	**$ 536,397**	**$ (844,854)**	**$ 1,967,777**
26	Cumulative Deferral (Rebate)/Surcharge Balance	Σ((23) ~ (25))			$ (119,583)	$ 767,235	$ 560,277	$ 880,333	$ 1,188,424	$ 1,189,344	$ 1,616,158	$ 1,532,132	$ 1,930,403	$ 2,276,234	$ 2,812,631	**$ 1,967,777**	
25	**Total Cumulative Deferral (Rebate)/Surcharge Balance**	**(13) + (26)**			$ (625,340)	$ 1,945,621	$ 4,089,805	$ 6,039,927	$ 8,528,126	$ 8,733,209	$ 8,201,335	$ 8,523,988	$ 9,044,601	$ 11,257,134	$ 13,579,523	**$ 12,255,982**	

Natural Gas Group 1 (Residential) and Group 2 (Non-Residential)

For natural gas, following steps in Schedule 175A, *Decoupled Revenue per Customer (by Rate Group)* is developed. Calculation of Decoupled Revenue per Customer (by Rate Group) is specified in seven steps in Schedule 175A. These steps are implemented in Table 1-24 and Table 1-25.[14] Monthly Decoupled Revenue per Customer for Group 1: Residential and Group 2: Non-Residential are then used to develop the *Monthly Decoupling Deferral* for natural gas, following the steps in Schedule 175B.

Schedule 175A – Decoupled Revenue per Customer

Step 1: Step 1 is to enter the Total Normalized Revenue, which is equal to the final approved base rate revenue approved in the Company's last general rate case, individually for each rate class. Table 1-24, Line 1 shows initial Total Normalized Net Revenue. In addition, Line 2 shows Allowed Revenue Increase. The sum of Line 1 and Line 2 is shown on Line 3 as the Total Rate Revenue (January 11, 2016). This corresponds to the full value specified in Step 1.

Step 2: Step 2 is to determine the Variable Gas Supply Revenue. This Variable Gas Supply Revenue is shown on Line 6. It the product of Normalized Therms by rate schedule from the last approved general rate case from Line 4 times the PGA Rates from Line 5.

Step 3: Step 3 is to determine Delivery Revenue, which is entered on Line 7. To determine the Delivery Revenue, the Variable Gas Supply Revenue is subtracted from the Total Normalized Revenue.

Step 4: Step 4 is to calculate the Basic Charge Revenue. Because the decoupling mechanism only tracks revenue that varies with customer energy usage, revenue from Fixed Charges is removed. It is the product of the number of Customer Bills in the test period on Line 8 times the Allowed Basic Charges (Line 9). The result, Basic Charge Revenue, is shown on Line 10.

Step 5: Determine the Allowed Decoupled Revenue. The Allowed Decoupled Revenue is equal to the Delivery (from Line 7) minus the Basic Charge Revenue (Line 10). The resulting Decoupled Revenue is shown on Line 11.

Step 6: In Step 6, Decoupled Revenue from Line 11 is put on a per customer basis. The Decoupled Revenue (by Rate Group) is divided by the approved Test Year number of customers (by Rate Group). This determines the annual Allowed Decoupled Revenue per Customer (by Rate Group) as shown in Table 1-25.

Step 7: Step 7 is different from the other steps because it converts the annual Allowed Decoupled Revenue per Customer (by Rate Group) into monthly values. The assignment of monthly values is carried out by first calculating the distribution of monthly therm use in the test year. This calculation is shown in Table 1-26.

[14] All tables in this section are attachments or parts of attachments to the Electric and Natural Gas Decoupling Rate Adjustment filings of August 31, 2017 for the 2016 deferral year.

In Table 1-26, therm use for Group 1 (Residential) for test year is shown in Line 4 and for Group 2 (Non-Residential) in Line 8. Both monthly therm values and the annual therm values are shown. Below the monthly values, percentages (Lines 5 and 9) are shown. Lines 14 and 18 show the use of these percentages, applied to annual Allowed Decoupled Revenue per Customer (by Rate Group) to generate monthly values.

These monthly values are then taken forward to be used in the implementation of Schedule 175B.

Table 1-24. 2016 Development of Natural Gas Decoupled Revenue per Customer

Avista Utilities
Natural Gas Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Natural Gas

	TOTAL	RESIDENTIAL SCHEDULE 101	GENERAL SVC. SCH. 111	LG. GEN. SVC. SCH. 121	INTERRUPTIBLE SCH 131	SCHEDULES 112, 122, 132	SCHEDULES 146 & 148
1 Total Normalized 12 ME Sept 2014 Revenue	$ 146,557,000	$ 106,954,000	$ 31,478,000	$ 2,973,000	$ -	$ 968,000	$ 4,184,000
2 Allowed Revenue Increase (Attachment 2)	$ 10,824,000	$ 8,398,000	$ 1,867,000	$ 161,000	$ -	$ 40,000	$ 358,000
3 Total Rate Revenue (January 11, 2016)	$ 157,381,000	$ 115,352,000	$ 33,345,000	$ 3,134,000	$ -	$ 1,008,000	$ 4,542,000
4 Normalized Therms (12ME Sept 2014 Test Year)	255,186,931	120,721,607	47,537,282	5,069,530	-	1,781,211	80,077,301
5 11/1/2015 Schedule 150 PGA Rates		$ 0.38907	$ 0.38166	$ 0.37077	$ 0.33645		
6 Variable Gas Supply Revenue	$ 66,991,864	$ 46,969,156	$ 18,143,079	$ 1,879,630	$ -		
7 Delivery Revenue (Ln 3 - Ln 6)	$ 84,839,136	$ 68,382,844	$ 15,201,921	$ 1,254,370	$ -		
8 Customer Bills (12ME Sept 2014 Test Year)	1,819,516	1,787,943	30,697	312	0	48	516
9 Allowed Basic Charges		$9.00	$101.44	$252.28	$0.00		
10 Basic Charge Revenue (Ln 8 * Ln 9)	$ 19,284,102	$ 16,091,487	$ 3,113,904	$ 78,711	$ -		
11 Decoupled Revenue	$ 65,555,034	$ 52,291,357	$ 12,088,017	$ 1,175,659	$ -	Excluded From Decoupling	

	Residential	Non-Residential Group
12 Average Number of Customers (Line 8 / 12)	148,995	2,584
13 Annual Therms	120,721,607	52,606,812
14 Basic Charge Revenues	$ 16,091,487	$ 3,192,615
15 Customer Bills	1,787,943	31,009
16 Average Basic Charge	$9.00	$102.96

Table 1-25. 2016 Natural Gas Decoupled Revenue per Customer

Avista Utilities

Natural Gas Decoupling Mechanism

Development of Decoupled Revenue Per Customer - Natural Gas

Line No.		Source	Residential	Non-Residential Schedules*
	(a)	(b)	(c)	(d)
1	Decoupled Revenues	Attachment 5, Page 1	$ 52,291,357	$ 13,263,676
2	Test Year # of Customers 12 ME 09.2014	Revenue Data	148,995	2,584
3	Decoupled Revenue Per Customer	(1) / (2)	$ 350.96	$ 5,132.84
	*Sales Schedules 111, 121, 131.			
		Revenues		
		From Revenue Per Customer	$ 52,291,373	$ 13,263,686
		From Basic Charges	$ 16,091,487	$ 3,192,615
		From Gas Supply	$ 46,969,156	$ 20,022,709
		Total	$ 115,352,016	$ 36,479,010

Table 1-26. 2016 Development of Monthly Natural Gas Decoupled Revenue per Customer

Avista Utilities
Natural Gas Decoupling Mechanism
'Development of Monthly Decoupled Revenue Per Customer - Natural Gas

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1															
2	**Natural Gas Delivery Volume**														
3	*Residential*														
4	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	21,149,989	17,496,849	14,113,448	7,866,788	4,895,089	2,998,022	2,095,088	2,047,777	2,727,612	8,666,827	14,928,966	21,735,152	120,721,607
5	- % of Annual Total	% of Total	17.52%	14.49%	11.69%	6.52%	4.05%	2.48%	1.74%	1.70%	2.26%	7.18%	12.37%	18.00%	100.00%
6															
7	*Non-Residential Sales**														
8	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	7,724,199	6,497,617	5,741,989	3,833,669	3,002,355	2,283,253	1,727,751	1,696,708	2,070,681	4,248,069	5,991,318	7,789,203	52,606,812
9	- % of Annual Total	% of Total	14.68%	12.35%	10.91%	7.29%	5.71%	4.34%	3.28%	3.23%	3.94%	8.08%	11.39%	14.81%	100.00%
10															
11	**Monthly Decoupled Revenue Per Customer ("RPC")**														
12	*Residential*														
13	-UG-150205 Decoupled RPC	Attachment 5, P. 2 L. 3													$ 350.96
14	-Monthly Decoupled RPC	(5) x (13)	$ 61.49	$ 50.87	$ 41.03	$ 22.87	$ 14.23	$ 8.72	$ 6.09	$ 5.95	$ 7.93	$ 25.20	$ 43.40	$ 63.19	$ 350.96
15															
16	*Non-Residential Sales**														
17	-UG-150205 Decoupled RPC	Attachment 5, P. 2 L. 3													$ 5,132.84
18	-Monthly Decoupled RPC	(9) x (17)	$ 753.65	$ 633.97	$ 560.25	$ 374.05	$ 292.94	$ 222.78	$ 168.58	$ 165.55	$ 202.04	$ 414.48	$ 584.57	$ 759.99	$ 5,132.84
19															
20	*Sales Schedules 111, 121, 131.														

Schedule 175B – Monthly Decoupling Deferral

Schedule 175B specifies the method for developing the *Monthly Decoupling Deferral* for natural gas service. For Group 1 (Residential), the calculation of the monthly decoupling deferral for January 2016 is shown in Table 1-27.[15] In the full version of this table (Table 1-28), the monthly decoupling deferral amounts across 2016 sum to the annual total decoupling deferral for 2016. As shown in Table 1-28, the annual total decoupling deferral for Residential natural gas is $7,152,977. The annual total decoupling deferral for Non-Residential natural gas is $2,002,654.

The individual steps in the Schedule 175B procedure are shown in both Table 1-27 and Table 1-28. [16]

Step 1: Step 1 is to Determine the actual number of customers each month. For Group 1 (Residential), this is shown in Line 1 of Table 1-27 and Table 1-28. For Group 2 (Non-Residential), this is shown in Line 11.

Step 2: Step 2 is to multiply the actual number of customers (Line 1 for Residential; Line 11 for Non-Residential) by the applicable monthly Allowed Decoupled Revenue per Customer (Line 2 for Residential; Line 12 for Non-Residential), which was developed in the Schedule 175A procedure. Allowed Decoupled Revenue for Residential is shown on Line 3. Allowed Decoupled Revenue for Non-Residential is shown on Line 13.

Step 3: Step 3 determines Actual Revenue collected. For Residential, this is shown on Line 4. For Non-Residential Actual Base Rate Revenue (Excluding Gas Costs) is shown on Line 14.

Step 4: Step 4 calculates the amount of Actual Fixed Charge Revenues included in Actual Revenues. This is shown on Line 5 for Residential and on Line 15 for Non-Residential.

Step 5: In Step 5, Actual Fixed Charge Revenue (Line 5 for Residential; Line 15 for Non-Residential) is subtracted from Actual Revenue (Line 4 for Residential; Line 14 for Non-Residential). The result is shown on Line 6 for Residential and on Line 16 for Non-Residential. At this point in the calculation all fixed charges have been removed, leaving only variable charges. In Table 1-28 this is shown as both Customer Decoupled Payments in total and as Revenue per Customer received.

Step 6: In Step 6, the difference between the Actual Decoupled Revenue from Step 5 (Line 6 for Residential and Line 16 for Non-Residential) and the Allowed Decoupled Revenue from Step 2 (Line 3 for Residential and Line 13 for Non-Residential) is calculated. The resulting balance (Lines 7, 8 and 9 for Residential and Lines 17, 18 and 19 for Non-Residential) is the Deferral Total.

Within Step 6, Line 7 for Residential and Line 17 for Non-Residential is the Direct Deferral (which is either a Surcharge or a Rebate).

[15] Only one month is shown here to keep the table readable on the page. The full natural gas deferral table is shown in Table 1-28.

[16] New rates became effective January 11, 2016. Deferred revenue calculations for the first 10 days of January 2016 were calculated at the rates prior to the change. January 11th through the 31st was calculated using the new rates.

Revenue Related Expense are stated on Line 8 for Residential and Line 18 for Non-Residential. Below this, the Federal Energy Regulatory Commission rate of interest (FERC Rate) is stated. Then, the result of the Average Balance Calculation is stated.

Line 9 (for Residential) and Line 19 (for Non-Residential) show the amount of Interest on Deferral. Below this, the result is the Deferral Totals.

For Residential, the Deferral Total is $7,152,977. This result is reported by Avista on Page 2 of 5 in the letter of transmittal from Patrick Ehrbar to the Commission dated August 31, 2017. For Non-Residential, the Deferral Total is $2,002,654. Since both are positive, both result in a surcharge. This result is reported by Avista on Page 3 of 5 in the letter of transmittal from Patrick Ehrbar to the Commission dated August 31, 2017.

Table 1-27. 2016 Natural Gas Deferral Calculations

Avista Utilities
Decoupling Mechanism - UG-150205 Base effective 1/11/2016
Development of WA Natural Gas Deferrals (Calendar Year 2016)

Line No.	(a)	Source (b)	32% Old Base	68% New Base	Pro Rated Jan-16 (c)
	Residential Group				
1	Actual Customers	Revenue System	49,326.45	103,585.55	152,912
2	Monthly Decoupled Revenue per Customer	Attachment 5, Page 3	$48.14	$61.49	$57.18
3	Decoupled Revenue	(1) x (2)	$ 2,374,462	$ 6,369,157	$ 8,743,619
	Actual Usage (informational only)	Revenue System	6,502,859	13,656,003	20,158,862
4	Actual Base Rate Revenue (Excludes Gas Costs)	Revenue System	$ 3,329,859	$ 6,992,704	$ 10,322,563
5	Actual Fixed Charge Revenue	Revenue System	$ 449,251	$ 943,427	$ 1,392,678
6	Customer Decoupled Payments	(4) - (5)	$ 2,880,608	$ 6,049,277	$ 8,929,885
	Residential Revenue Per Customer Received		$58.40	$58.40	$58.40
7	Deferral - Surcharge (Rebate)	(3) - (6)	$ (506,146)	$ 319,880	$ (186,266)
8	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 22,674	$ (14,608)	$ 8,066
		FERC Rate			3.25%
9	Interest on Deferral	Avg Balance Calc			$ (241)
	Monthly Residential Deferral Totals				**$ (178,442)**
10	Cumulative Deferral (Rebate) Balance	Σ((7) + (9))			$ (178,442)
	Non-Residential Group				
11	Actual Customers	Revenue System	859.35	1,804.65	2,664
12	Monthly Decoupled Revenue per Customer	Attachment 5, Page 3	$642.24	$753.65	$717.71
13	Decoupled Revenue	(11) x (12)	$ 551,908	$ 1,360,069	$ 1,911,977
	Actual Usage (informational only)				6,913,974
14	Actual Base Rate Revenue (Excludes Gas Costs)	Revenue System	$ 642,749	$ 1,349,772	$ 1,992,521
15	Actual Fixed Charge Revenue	Revenue System	$ 78,920	$ 165,731	$ 244,651
16	Customer Decoupled Payments	(14) - (15)	$ 563,829	$ 1,184,041	$ 1,747,870
	Non-Residential Revenue Per Customer Received		$656.11	$656.11	$656.11
17	Deferral - Surcharge (Rebate)	(13) - (16)	$ (11,921)	$ 176,028	$ 164,107
18	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 534	$ (8,039)	$ (7,505)
		FERC Rate			3.25%
19	Interest on Deferral	Avg Balance Calc			$ 212
	Monthly Non-Residential Deferral Totals				**$ 156,815**
20	Cumulative Deferral Surcharge(Rebate) Balance	Σ((17) + (19))			$ 156,815
21	**Total Cumulative Deferral (Rebate)**	**(10) + (20)**			$ (21,627)

Table 1-28. 2016 Development of Natural Gas Deferral

Avista Utilities
Decoupling Mechanism - UG-150205 Base effective 1/11/2016
Development of WA Natural Gas Deferrals (Calendar Year 2016)

Line No.		Source	32% Old Base	68% New Base	Pro Rated Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
	(a)	(b)			(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Residential Group																
1	Actual Customers	Revenue System	49,326.45	103,585.55	152,912	153,882	153,511	153,360	153,389	153,224	153,459	153,740	154,156	154,684	155,353	155,792	1,847,462
2	Monthly Decoupled Revenue per Customer	Attachment 5, Page 3	$48.14	$61.49	$57.18	$50.87	$41.03	$22.87	$14.23	$8.72	$6.09	$5.95	$7.93	$25.20	$43.40	$63.19	$346.65
3	Decoupled Revenue	(1) x (2)	$ 2,374,462	$ 6,369,157	$ 8,743,619	$ 7,827,450	$ 6,298,618	$ 3,507,375	$ 2,182,868	$ 1,335,470	$ 934,689	$ 915,255	$ 1,222,406	$ 3,897,428	$ 6,742,516	$ 9,844,200	$ 53,451,894
	Actual Usage (informational only)	Revenue System	6,502,859	13,656,003	20,158,862	14,311,636	12,256,797	5,360,973	3,390,462	2,769,530	2,296,193	2,357,534	3,002,763	7,275,160	11,371,978	24,244,299	108,796,187
	Actual Base Rate Revenue																
4	(Excludes Gas Costs)	Revenue System	$ 3,329,859	$ 6,992,704	$ 10,322,563	$ 7,563,312	$ 6,495,025	$ 3,429,418	$ 2,661,586	$ 2,472,638	$ 2,330,790	$ 2,442,106	$ 2,634,492	$ 4,372,688	$ 6,355,325	$ 11,925,970	$ 63,005,913
5	Actual Fixed Charge Revenue	Revenue System	$ 449,251	$ 943,427	$ 1,392,678	$ 1,402,065	$ 1,398,500	$ 1,402,389	$ 1,406,025	$ 1,409,895	$ 1,407,339	$ 1,413,126	$ 1,411,704	$ 1,414,453	$ 1,417,988	$ 1,420,221	$ 16,896,382
6	Customer Decoupled Payments	(4) - (5)	$ 2,880,608	$ 6,049,277	$ 8,929,885	$ 6,161,247	$ 5,096,525	$ 2,027,029	$ 1,255,561	$ 1,062,743	$ 923,451	$ 1,028,980	$ 1,222,788	$ 2,958,235	$ 4,937,338	$ 10,505,750	$ 46,109,530
	Residential Revenue Per Customer Received		$58.40	$58.40	$58.40	$40.04	$33.20	$13.22	$8.19	$6.94	$6.02	$6.69	$7.93	$19.12	$31.78	$67.43	
7	Deferral - Surcharge (Rebate)	(3) - (6)	$ (506,146)	$ 319,880	$ (186,266)	$ 1,666,203	$ 1,202,093	$ 1,480,346	$ 927,307	$ 272,727	$ 11,238	$ (113,725)	$ (382)	$ 939,193	$ 1,805,178	$ (661,549)	$ 7,342,364
8	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 22,674	$ (14,608)	$ 8,066	$ (76,092)	$ (54,897)	$ (67,604)	$ (42,348)	$ (12,455)	$ (513)	$ 5,194	$ 17	$ (42,891)	$ (82,439)	$ 30,212	$ (335,752)
		FERC Rate			3.25%	3.25%	3.25%	3.46%	3.46%	3.46%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
9	Interest on Deferral	Avg Balance Calc			$ (241)	$ 1,670	$ 5,381	$ 9,435	$ 12,775	$ 14,463	$ 15,067	$ 14,969	$ 14,853	$ 16,203	$ 20,070	$ 21,720	$ 146,365
	Monthly Residential Deferral Totals				**$ (178,442)**	**$ 1,591,781**	**$ 1,152,577**	**$ 1,422,177**	**$ 897,734**	**$ 274,735**	**$ 25,792**	**$ (93,563)**	**$ 14,489**	**$ 912,505**	**$ 1,742,809**	**$ (609,617)**	**$ 7,152,977**
10	Cumulative Deferral (Rebate) Balance	Σ((7) + (9))			$ (178,442)	$ 1,413,339	$ 2,565,916	$ 3,988,093	$ 4,885,826	$ 5,160,561	$ 5,186,354	$ 5,092,791	$ 5,107,280	$ 6,019,785	$ 7,762,595	$ 7,152,977	
	Non-Residential Group																
11	Actual Customers	Revenue System	859.35	1,804.65	2,664	2,705	2,708	2,797	2,769	2,793	2,794	2,775	2,794	2,798	2,812	2,833	33,242
12	Monthly Decoupled Revenue per Customer	Attachment 5, Page 3	$642.24	$753.65	$717.71	$633.97	$560.25	$374.05	$292.94	$222.78	$168.58	$165.55	$202.04	$414.48	$584.57	$759.99	$5,096.90
13	Decoupled Revenue	(11) x (12)	$ 551,908	$ 1,360,069	$ 1,911,977	$ 1,714,893	$ 1,517,144	$ 1,046,220	$ 811,149	$ 622,215	$ 471,003	$ 459,395	$ 564,489	$ 1,159,725	$ 1,643,817	$ 2,153,056	$ 14,075,082
	Actual Usage (informational only)				6,913,974	5,609,302	5,156,824	2,896,859	2,532,832	1,900,306	1,776,830	1,842,874	2,260,370	4,076,896	4,431,065	8,810,762	48,208,894
	Actual Base Rate Revenue																
14	(Excludes Gas Costs)	Revenue System	$ 642,749	$ 1,349,772	$ 1,992,521	$ 1,706,491	$ 1,603,845	$ 1,020,533	$ 884,603	$ 726,949	$ 690,821	$ 709,441	$ 818,005	$ 1,285,548	$ 1,504,422	$ 2,468,211	$ 15,411,390
15	Actual Fixed Charge Revenue	Revenue System	$ 78,920	$ 165,731	$ 244,651	$ 275,956	$ 279,705	$ 288,136	$ 285,292	$ 287,768	$ 287,473	$ 286,537	$ 287,792	$ 287,908	$ 324,817	$ 258,141	$ 3,394,177
16	Customer Decoupled Payments	(14) - (15)	$ 563,829	$ 1,184,041	$ 1,747,870	$ 1,430,535	$ 1,324,140	$ 732,397	$ 599,311	$ 439,181	$ 403,348	$ 422,904	$ 530,213	$ 997,640	$ 1,179,605	$ 2,210,070	$ 12,017,213
	Non-Residential Revenue Per Customer Received		$656.11	$656.11	$656.11	$528.85	$488.97	$261.85	$216.44	$157.24	$144.36	$152.40	$189.77	$356.55	$419.49	$780.12	
17	Deferral - Surcharge (Rebate)	(13) - (16)	$ (11,921)	$ 176,028	$ 164,107	$ 284,359	$ 193,004	$ 313,823	$ 211,838	$ 183,034	$ 67,655	$ 36,491	$ 34,276	$ 162,085	$ 464,212	$ (57,014)	$ 2,057,869
18	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 534	$ (8,039)	$ (7,505)	$ (12,986)	$ (8,814)	$ (14,332)	$ (9,674)	$ (8,359)	$ (3,090)	$ (1,666)	$ (1,565)	$ (7,402)	$ (21,200)	$ 2,604	$ (93,989)
		FERC Rate			3.25%	3.25%	3.25%	3.46%	3.46%	3.46%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
19	Interest on Deferral	Avg Balance Calc			$ 212	$ 792	$ 1,411	$ 2,204	$ 2,933	$ 3,485	$ 3,884	$ 4,041	$ 4,151	$ 4,436	$ 5,321	$ 5,903	$ 38,775
	Monthly Non-Residential Deferral Totals				**$ 156,815**	**$ 272,165**	**$ 185,601**	**$ 301,695**	**$ 205,097**	**$ 178,160**	**$ 68,449**	**$ 38,865**	**$ 36,861**	**$ 159,119**	**$ 448,333**	**$ (48,507)**	**$ 2,002,654**
20	Cumulative Deferral Surcharge(Rebate) Balance	Σ((17) + (19))			$ 156,815	$ 428,979	$ 614,580	$ 916,275	$ 1,121,373	$ 1,299,533	$ 1,367,982	$ 1,406,848	$ 1,443,709	$ 1,602,828	$ 2,051,162	$ 2,002,654	
21	**Total Cumulative Deferral (Rebate)**	**(10) + (20)**			$ (21,627)	$ 1,842,318	$ 3,180,496	$ 4,904,368	$ 6,007,199	$ 6,460,094	$ 6,554,336	$ 6,499,639	$ 6,550,989	$ 7,622,614	$ 9,813,756	$ 9,155,632	

2016 Earnings Test

The decoupling mechanism, in Schedules 75D and 175D provides for application of an earnings test, separately for electric and for natural gas.

Schedule 75D – Electric Earnings Test

According to Schedule 75D, the decoupling mechanism for decoupled electric customers is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues and various normalizing adjustments. As shown in Table 1-29, Line 3, the rate of return on a normalized basis in 2016 is 7.51%. This exceeds the 7.29% allowed return established by Order 05 of Docket No. UE-150204[17] (Line 4). The Excess ROR is 0.22%, corresponding to Excess Earnings of $3,218,417 (Line 6). A Conversion Factor is entered on Line 7, which is divided into the Excess Earnings to produce Excess Revenue (Line 8) of $5,193,843. When the 50% Sharing (Line 9) is applied, the Total Earnings Sharing for electric is $2,596,921 (Line 10).

Table 1-29. 2016 Electric Earnings Test

Line No.		Electric
1	Rate Base	$ 1,442,726,000
2	Net Income	$ 108,405,000
3	Calculated ROR	7.51%
4	Base ROR	7.29%
5	Excess ROR	0.22%
6	Excess Earnings	$ 3,218,417
7	Conversion Factor	0.619660
8	Excess Revenue (Excess Earnings/CF)	$ 5,193,843
9	Sharing %	50%
10	2016 Total Earnings Test Sharing	**$ 2,596,921**

The Electric Total Earnings Test Sharing amount is then split between residential and non-residential customer groups in proportion to their contribution to Total Normalized Revenue (Table 1-30). The split is 50.62% Electric Residential and 49.38% Electric Non-Residential.

The dollar values for the split are $1,314,495 Electric Residential (Line 14) and $1,282,427 Electric Non-Residential (Line 15). These values are adjusted to remove various revenue related expenses by dividing them by the Gross Up Factor derived in Table 1-31 (1.048963). The final

[17] Page 6, Paragraph 5 (Commission Determinations) in Washington Utilities and Transportation Commission v. Avista Corporation dba Avista Utilities, Dockets UE-150204 and UG-150205 (Consolidated), Order 05, Final Order Rejecting Tariff Finding, Accepting Partial Settlement Stipulation, Authorizing Tariff Findings. Service Date January 26, 2016.

values for the Electric Earnings Test are $1,253,138 for Residential Electric and $1,222,566 for Non-Residential Electric. These values are shown on Line 14 and Line 15, respectively, in Table 1-30. These are also reported on Page 2 of 6 (Residential) and Page 3 of 6 (Non-Residential) of the Letter of Transmittal from Patrick Ehrbar to the Commission for the Electric Decoupling Rate Adjustment, Tariff WN U-28, Electric Service, dated August 31, 2017.

Table 1-30. 2016 Electric Earnings Test Sharing Adjustment

	Revenue From 2016 Normalized Loads and Customers at Present Billing Rates			
11	Residential Revenue		$ 223,399,000	50.62%
12	Non-Residential Revenue		$ 217,949,000	49.38%
13	Total Normalized Revenue		$ 441,348,000	100.00%
			Gross Revenue	Net of Revenue
	Earnings Test Sharing Adjustment		Adjustment	Related Expenses
14	Residential		$ 1,314,495	$ 1,253,138
15	Non-Residential		$ 1,282,427	$ 1,222,566
16	Total		$ 2,596,921	$ 2,475,704

Table 1-31. Derivation of 2016 Electric Gross Up Factor and Revenue Conversion Factor

AVISTA UTILITIES
Revenue Conversion Factor
Washington - Electric System
TWELVE MONTHS ENDED December 31, 2016

Line No.	Description	Factor
1	**Revenues**	1.000000
	Expense:	
2	Uncollectibles	0.006183
3	Commission Fees	0.002000
4	Washington Excise Tax	0.038495
5	Total Expense	0.046677
6	Net Operating Income Before FIT	0.953323
7	Federal Income Tax @ 35%	0.333663
8	**REVENUE CONVERSION FACTOR**	0.619660
9	Gross Up Factor	1.048963

2016 Commission Basis Conversion Factor with Uncollectible Service Correction

Schedule 175D – Natural Gas Earnings Test

According to Schedule 175D, the decoupling mechanism for natural gas is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues and various normalizing adjustments. As shown in Table 1-32, the rate of return on a normalized basis in 2016 is 8.56%. This is more than the 7.29% allowed return[18] (Line 4). The Excess ROR is 1.27% (Line 5). The dollar value of Excess Earnings is $3,628,723. This is adjusted for various revenue expenses by dividing by the Conversion Factor (0.619798) given in Line 7 for Excess Revenue of $5,854,687 as shown in Line 8.

Table 1-32. 2016 Natural Gas Earnings Test

	2016 Commission Basis Earnings Test for Decoupling	
Line No.		Natural Gas
1	Rate Base	$ 286,597,000
2	Net Income	$ 24,524,000
3	Calculated ROR	8.56%
4	Base ROR	7.29%
5	Excess ROR	1.27%
6	Excess Earnings	$ 3,628,723
7	Conversion Factor	0.619798
8	Excess Revenue (Excess Earnings/CF)	$ 5,854,687
9	Sharing %	50%
10	2016 Total Earnings Test Sharing	**$ 2,927,343**

With the Sharing percentage set at 50%, the 2016 Total Earnings Test Sharing is $2,927,343 (Line 10). The Conversion Factor on Line 7 of Table 1-32 is developed in Table 1-33.

[18] Page 6, Paragraph 5 (Commission Determinations) in Washington Utilities and Transportation Commission v. Avista Corporation dba Avista Utilities, Dockets UE-150204 and UG-150205 (Consolidated), Order 05, Final Order Rejecting Tariff Finding, Accepting Partial Settlement Stipulation, Authorizing Tariff Findings. Service Date January 26, 2016.

Table 1-33. Derivation of 2016 Natural Gas Gross Up Factor and Revenue Conversion Factor

AVISTA UTILITIES
Revenue Conversion Factor
Washington - Gas System
TWELVE MONTHS ENDED December 31, 2016

Line No.	Description	Factor
1	**Revenues**	1.000000
	Expense:	
2	Uncollectibles	0.006183
3	Commission Fees	0.002000
4	Washington Excise Tax	0.038282
5	Total Expense	0.046465
6	Net Operating Income Before FIT	0.953535
7	Federal Income Tax @ 35%	0.333737
8	REVENUE CONVERSION FACTOR	0.619798
9	Gross Up Factor	1.048729

2016 Commission Basis Conversion Factor with Uncollectible Service Correction

The split between Natural Gas Residential and Natural Gas Non-Residential is developed in Table 1-34. The split is modeled on contribution to revenue. Stated in percentage terms, the split is 76.15% Residential and 23.85% Non-Residential (Lines 11 and 12). At the Gross level, the dollar values are $2,229,293 Residential and $698,050 Non-Residential. When expressed net of various revenue expenses (by dividing by the Gross Up Factor from Table 1-33, Line 9, the values are $2,125,710 Natural Gas Residential and $665,616 Natural Gas Non-Residential. These values are also reported Page 2 of 5 for Residential and Page 3 of 5 for Non-Residential in Letter of Transmittal from Patrick Ehrbar to the Commission for the Natural Gas Decoupling Rate Adjustment, Tariff WN U-28, Electric Service, dated August 31, 2017.

Table 1-34. 2016 Natural Gas Earnings Test Sharing Adjustment

	Revenue From 2016 Normalized Loads and Customers at Present Billing Rates		
11	Residential Revenue	$ 110,176,000	76.15%
12	Non-Residential Revenue	$ 34,499,000	23.85%
13	Total Normalized Revenue	$ 144,675,000	100.00%
	Earnings Test Sharing Adjustment	Gross Revenue Adjustment	Net of Revenue Related
14	Residential	$ 2,229,293	$ 2,125,710
15	Non-Residential	$ 698,050	$ 665,616
16	Total	$ 2,927,343	$ 2,791,326

2016 Three-Percent Annual Rate Increase Limitation

Decoupling annual rate adjustment surcharges are subject to a 3% annual rate increase limitation (there is no reciprocal limit on rebate rate adjustments). The test is to divide the *incremental* annual revenue to be collected (proposed surcharge revenue minus present surcharge revenue) by the total "normalized" revenue for the two Rate Groups for the most recent January through December.

Normalized revenue is determined by multiplying the weather-corrected usage for the period by the present rates in effect. If the incremental amount of the proposed surcharge exceeds 3%, only a 3% incremental rate increase will apply. Any remaining deferred revenue will be carried over to the following years.

Schedule 75E – Electric 3% Rate Increase Test

The electric Incremental Surcharge Test is shown in Table 1-35. Following the specifications for the test limits the Residential Surcharge to 3% with the remainder deferred to the following year.

However, division of the Revenue from 2016 Normalized Loads with Customers at Present Billing Rates (Line 1) by the Incremental Decoupling Recovery (Line 6) results in a value of 2.0% for Electric Residential and a value of 0.4% for Electric Non-Residential (Line 7). Since these values are both less than 3%, no adjustment is necessary for either Electric Residential or for Electric Non-Residential. For both Electric Rate Groups, the Carryover Deferred Revenue is equal to zero.

Table 1-35. 2016 Electric 3% Incremental Surcharge Test

Line No.	3% Incremental Surcharge Test	Residential	Non-Residential
1	Revenue From 2016 Normalized Loads and Customers at Present Billing Rates (Note 1)	$ 223,399,000	$ 217,949,000
2	November 2017 - October 2018 Usage (kWhs)	2,452,572,967	2,160,028,828
3	Proposed Decoupling Recovery Rates	$0.00445	$0.00040
4	Present Decoupling Surcharge Recovery Rates	$0.00263	$0.00000
5	Incremental Decoupling Recovery Rates	$0.00182	$0.00040
6	Incremental Decoupling Recovery	$ 4,463,683	$ 864,012
7	Incremental Surcharge %	**2.00%**	**0.40%**
8	3% Test Adjustment (Note 2)	$ -	$ -
9	3% Test Rate Adjustment	$0.00000	$0.00000
10	Adjusted Proposed Decoupling Recovery Rates	$0.00445	$0.00040
11	Adjusted Incremental Decoupling Recovery	$ 4,463,683	$ 864,012
12	Adjusted Incremental Surcharge %	**2.00%**	**0.40%**
	Notes		
	(1) 2016 Normalized Revenue derived from UE-170485 Revenue Model with billed rates adjusted to reflect August 1, 2017 present rates.		
	(2) The carryover balances will differ from the 3% adjustment amounts due to the revenue related expense gross up partially offset by additional interest on the outstanding balance during the amortization period.		

Schedule 175E – Natural Gas 3% Rate Increase Test

The natural gas Incremental Surcharge Test is shown in Table 1-36. The test limits the residential and the non-residential surcharge each to 3%.

For the natural gas residential group, there is an additional revenue amount of $718,577 that is deferred to the following year because of the test (Line 8). For the natural gas non-residential group, the surcharge is less than 3% so the deferred revenue carried forward to the following year is equal to zero.

Table 1-36. 2016 Natural Gas 3% Incremental Surcharge Test

Line No.	**3% Incremental Surcharge Test**	Residential	Non-Residential
1	Revenue From 2016 Normalized Loads and Customers at Present Billing Rates (Note 1)	$ 110,176,000	$ 34,499,000
2	November 2017 - October 2018 Usage	124,577,619	56,682,411
3	Proposed Decoupling Recovery Rates	$0.06157	$0.03904
4	Present Decoupling Surcharge Recovery Rates	$0.02927	$0.02108
5	Incremental Decoupling Recovery Rates	$0.03230	$0.01796
6	Incremental Decoupling Recovery	$ 4,023,857	$ 1,018,016
7	Incremental Surcharge %	**3.65%**	**2.95%**
8	3% Test Adjustment (1)	$ (718,577)	$ -
9	3% Test Rate Adjustment	-$0.00577	$0.00000
10	Adjusted Proposed Decoupling Recovery Rates	$0.05580	$0.03904
11	Adjusted Incremental Decoupling Recovery	$ 3,305,044	$ 1,018,016
12	Adjusted Incremental Surcharge %	**3.00%**	**2.95%**
	Notes		
	(1) 2016 Normalized Revenue derived from UG-170486 Revenue Model with billed rates adjusted to reflect August 1, 2017 present rates.		
	(2) The carryover balances will differ from the 3% adjustment amounts due to the revenue related expense gross up partially offset by additional interest on the outstanding balance during the amortization period.		

Decoupling Mechanism - 2017 Electric (Schedule 75) and Natural Gas (Schedule 175)

In this section, we review analysis of data from the test year from October 2013 through September 2014 (a historical test year), which was used to develop amounts for revenue recovery for calendar 2017. Recovery will occur from November 2018 through the end of October 2019 (the third rate year). The decoupling mechanism is designed to capture all fixed cost assigned for recovery through volumetric rates that is not actually recovered due to lower sales than expected during calendar 2017. This cost is recovered by allocation to customer bills according to a model. The decoupling deferrals total is based on comparison of the value of actual sales in calendar 2017 to the value of normalized sales (from October 2013 through September 2014) on a per customer basis. Note that the 2017 deferral year uses the same test year and decoupled revenue per customer as 2016.

As specified in Schedule 75 and Schedule 175, calculations were carried out separately and in parallel, for Residential and Non-Residential accounts. For each of these groups of accounts, the sum of monthly deferral amounts over calendar year 2017 is the cumulative deferral (rebate or surcharge). The cumulative deferral (with adjustments for prior year carryover balance, interest, and revenue related expense adjustment) is collected through the decoupling tariff on a volumetric basis from November 1, 2018 through October 31, 2019.

Electric Group 1 (Residential) and Group 2 (Non-Residential)

First the electric service analysis is reviewed, then the analysis for natural gas service.

Schedule 75A – Decoupled Revenue per Customer

For electric service, following steps in Schedule 75A, *Decoupled Revenue per Customer (by Rate Group)* is developed. Calculation of Decoupled Revenue per Customer (by Rate Group) is specified in seven steps in Schedule 75A. Electric tables for 2017 are attachments or parts of attachments to the Tariff WN U-28, Electric Service, Electric Decoupling Rate Adjustment filed August 17, 2018.

Step 1: Step 1 is to enter the Total Normalized 12 ME September, 2014 Revenue, which is equal to the final approved base rate revenue approved in the Company's last general rate case, individually for each Rate Schedule. Table 1-37, Line 1 shows initial Total Normalized Net Revenue. In addition, Line 2 shows the Allowed Revenue Increase. The sum of Line 1 and Line 2 is shown on Line 3 as the Total Rate Revenue (January 11, 2016). This corresponds to the full value specified in Step 1.

Step 2: Step 2 is to determine the Variable Power Supply Revenue. This value is shown on Line 6 and is the product of Normalized kWh for the test year from Line 4 and Retail Revenue Adjustment from Line 5.

Step 3: Step 3 is to enter Delivery and Power Plant Revenue. This is constructed by subtraction of Variable Power Supply Revenue (Line 6) from the Total Normalized Revenue (Line 3) and is entered on Line 7.

Step 4: Step 4 is to Remove Basic Charge Revenue. Because the decoupling mechanism only tracks revenue that varies with customer energy usage, revenue from Fixed Charges is removed. Basic Charge Revenue is shown on Line 10. It is the product of the number of Customer Bills in the GRC test year on Line 8 times the Allowed Basic Charge (Line 9).

Step 5: In Step 5, the Decoupled Revenue is equal to the Delivery and Power Plant Revenue (Line 7) minus the Basic Charge Revenue (Line 10). Decoupled Revenue is shown on Line 11.

Step 6: In Step 6, (see Table 1-38) Decoupled Revenue is put on a per customer basis. The Decoupled Revenue (by Rate Group) is divided by the approved Test Year number of customers (by Rate Group). This determines the annual Allowed Decoupled Revenue per Customer (by Rate Group).

Step 7: Step 7 is different from the other steps because it converts the annual Allowed Decoupled Revenue per Customer (by Rate Group) into monthly values. The assignment of monthly values is carried out by modeling monthly kWh use (by Rate Group) in relationship to the annual kWh use for the test year. This modeling is shown in Table 1-39. Kilowatt hours for Group 1 (Residential) for the test year is shown in Line 3 and for Group 2 (Non-Residential) in Line 6. Both monthly values and the annual kWh values are shown. Below the monthly values (Lines 4 and 7) monthly percentages are shown. Lines 11 and 14 use this percentage model, applied to annual Allowed Decoupled Revenue per Customer (by Rate Group), to generate monthly values.

The monthly values developed following the steps in Schedule 75A are then taken forward to be used in the implementation of Schedule 75B.

Table 1-37. 2017 Development of Electric Decoupled Revenue per Customer

Avista Utilities
Electric Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Electric

		TOTAL	RESIDENTIAL SCHEDULE 1	GENERAL SVC. SCH. 11,12	LG. GEN. SVC. SCH. 21,22	PUMPING SCH. 30, 31, 32	EX LG GEN SVC SCHEDULE 25	ST & AREA LTG SCH. 41-48
1	Total Normalized 12 ME Sept 2014 Revenue	$ 499,982,000	$ 214,841,000	$ 71,304,000	$ 130,152,000	$ 11,471,000	$ 65,194,000	$ 7,020,000
2	Allowed Revenue Increase (Attachment 1)	$ (8,110,000)	$ (3,478,000)	$ (1,159,000)	$ (2,118,000)	$ (187,000)	$ (1,056,000)	$ (112,000)
3	Total Rate Revenue (January 11, 2016)	$ 491,872,000	$ 211,363,000	$ 70,145,000	$ 128,034,000	$ 11,284,000	$ 64,138,000	$ 6,908,000
4	Normalized kWhs (12ME Sept 2014 Test Year)	5,653,834,483	2,378,478,031	588,401,236	1,419,228,271	137,227,044	1,105,372,136	25,127,765
5	Retail Revenue Adjustment (line 14)	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641
6	Variable Power Supply Revenue (L4 * L5)	$ 92,779,424	$ 39,030,824	$ 9,655,664	$ 23,289,536	$ 2,251,896	$ 18,139,157	$ 412,347
7	Delivery & Power Plant Revenue (L3 - L6)	$ 346,598,080	$ 172,332,176	$ 60,489,336	$ 104,744,464	$ 9,032,104		
8	Customer Bills (12ME Sept 2014 Test Year)	2,879,945	2,462,067	364,552	24,110	29,216		
9	Allowed Basic Charges		$ 8.50	$ 18.00	$ 500.00	$ 18.00		
10	Basic Charge Revenue (Ln 8 * Ln 9)	$ 40,070,394	$ 20,927,570	$ 6,561,936	$ 12,055,000	$ 525,888		
11	Decoupled Revenue	$ 306,527,686	$ 151,404,606	$ 53,927,400	$ 92,689,464	$ 8,506,216	Excluded From Decoupling	
12	Retail Revenue Adjustment - (Attachment 3)	$0.01566						
13	Gross Up Factor for Revenue Related Exp	104.81%						
14	Grossed Up Retail Revenue Adjustment	$0.01641						
			Residential	Non-Residential Group				
15	Average Number of Customers (Line 8 / 12)		205,172	34,823				
16	Annual kWh		2,378,478,031	2,144,856,551				
17	Basic Charge Revenues		20,927,570	19,142,824				
18	Customer Bills		2,462,067	417,878				
19	Average Basic Charge		$8.50	$45.81				

Table 1-38. 2017 Electric Decoupled Revenue per Customer

Avista Utilities
Electric Decoupling Mechanism
Development of Annual Decoupled Revenue Per Customer - Electric

Line No.		Source		Residential		Non-Residential Schedules*
	(a)	(b)		(c)		(d)
1	Decoupled Revenues	Attachment 4, Page 1	$	151,404,606	$	155,123,080
2	Test Year # of Customers 12 ME 09.2014	Revenue Data		205,172		34,823
3	Decoupled Revenue per Customer	(1) / (2)	$	737.94	$	4,454.59
	* Schedules 11, 12, 21, 22, 31, 32.					
	Revenues					
	From revenue per customer		$	151,404,810	$	155,122,930
	From basic charge		$	20,927,570	$	19,142,824
	From power supply		$	39,030,824	$	35,197,096
	Total		$	211,363,204	$	209,462,850

Table 1-39. 2017 Development of Monthly Electric Decoupled Revenue per Customer

Avista Utilities
Electric Decoupling Mechanism
Development of Monthly Decoupled Revenue Per Customer - Electric

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**Electric Sales**														
2	*Residential*														
3	- Weather-Normalized kWh Sales	Monthly Rate Year	284,675,925	232,597,855	228,752,581	172,322,869	166,632,549	148,170,954	153,360,033	181,322,317	146,560,541	174,054,557	212,665,464	277,362,386	2,378,478,031
4	- % of Annual Total	% of Total	11.97%	9.78%	9.62%	7.25%	7.01%	6.23%	6.45%	7.62%	6.16%	7.32%	8.94%	11.66%	100.00%
5	*Non-Residential**														
6	- Weather-Normalized kWh Sales	Monthly Rate Year	174,546,983	177,500,854	166,289,029	165,417,455	178,108,889	185,503,197	200,737,081	187,588,012	179,420,897	183,203,251	168,530,619	178,010,284	2,144,856,551
7	- % of Annual Total	% of Total	8.14%	8.28%	7.75%	7.71%	8.30%	8.65%	9.36%	8.75%	8.37%	8.54%	7.86%	8.30%	100.00%
8	**Monthly Decoupled Revenue Per Customer ("RPC")**														
9	*Residential*														
10	-UE-150204 Decoupled RPC	Attachment 4, P. 2 L. 3													$ 737.94
11	- Monthly Decoupled RPC	(4) x (10)	$ 88.32	$ 72.17	$ 70.97	$ 53.46	$ 51.70	$ 45.97	$ 47.58	$ 56.26	$ 45.47	$ 54.00	$ 65.98	$ 86.05	$ 737.94
12	*Non-Residential**														
13	-UE-150204 Decoupled RPC	Attachment 4, P. 2 L. 3													$ 4,454.59
14	- Monthly Decoupled RPC	(7) x (13)	$ 362.51	$ 368.65	$ 345.36	$ 343.55	$ 369.91	$ 385.27	$ 416.90	$ 389.60	$ 372.63	$ 380.49	$ 350.02	$ 369.70	$ 4,454.59

* Schedules 11, 12, 21, 22, 31, 32.

Schedule 75B - Monthly Decoupling Deferral

Schedule 75B specifies the method for developing the *Monthly Decoupling Deferral* for electric service. For Group 1 (Residential), the calculation of the monthly decoupling deferral for January 2017 is shown in the top part of Table 1-40.[19] For Group 2 (Non-Residential) the calculation method is shown in the bottom part of Table 1-40. In the full version of this table (Table 1-41), the monthly decoupling deferral amounts across 2017 sum to the annual total decoupling deferral for 2017. For the Electric Residential, deferred revenue for 2017 is negative with a value of ($2,092,790). For Electric Non-Residential, deferred revenue for 2017 is $1,735,911.

Residential Decoupling Deferrals (Step 2 of Schedule 75B) corresponds to Line 3 in the top part of Table 1-40 and the top part of Table 1-41. It is calculated by multiplying the number of Actual Customers (Line 1) by the Monthly Decoupled Revenue per Customer (Line 2).

Residential Actual Revenue collected in a month (Step 3 of Schedule 75B) is shown on Line 4.

The Residential Actual Basic Charge Revenue (Step 4) is shown on Line 5. The total revenue collected related to the variable power supply (Step 5) is shown on Line 8. This is the product of Actual kWh Sales (Line 6) and the Retail Revenue Credit (Line 7).

Residential Actual Decoupled Revenue (Step 6) is calculated by subtracting the Actual Basic Charge Revenue (Line 4) and the variable power supply revenue (Line 8) from the Actual Base Rate Revenue and is shown on Line 9.

The Monthly Residential Deferral Total for each month (Step 7) is shown just below Line 12. This is the difference between the Actual Decoupled Revenue (Step 6; Line 9) and the Allowed Decoupled Revenue (Step 2; Line 3) plus any interest on the deferral. Interest on the deferred balance accrues at the quarterly rate published by the FERC. In Table 1-41, these values are cumulatively incremented by month over 2017 on Line 13 and the electric deferred revenue for 2017 shown on Line 13 with the value of minus $2,092,790. This is the Residential value given by Avista on page 2 of 5 in Tariff WN U-28, Electric Service, Electric Decoupling Rate Adjustment filing in compliance with Commission Order No. 05 in Docket No. UE-140188 on August 17, 2018. Since the value is negative, Electric Residential does not receive a surcharge.

For Electric Non-Residential, Schedule 75B specifies the method for developing the Monthly Decoupling Deferral for electric service. In the full version of this table (bottom section of Table 1-41), the monthly decoupling deferral amounts across 2017 sum to the annual total decoupling deferral for 2017 (for Electric Non-Residential) of $1,735,911. This is the Electric Non-Residential value given on Page 3 of 5 in the Electric Decoupling Rate Adjustment filing in compliance with Commission Order No. 05 in Docket No. UE-140188 on August 17, 2018. Since deferred revenue is positive, Electric Non-Residential receives a surcharge. The surcharge is adjusted by the Earnings Sharing Deduction, the Prior Year Residual Balance, and by Revenue Related Expense Adjustment for a final Customer Surcharge Revenue Amount of $1,170,966.

[19] Only the first few columns of the table are shown here to keep the table readable on the page.

The calculations and the Excel programming are identical for Electric Residential and Electric Non-Residential.

Table 1-40. 2017 Electric Deferral Calculations

Avista Utilities
Decoupling Mechanism - UE-150204 Base effective 1/11/2016
Development of WA Electric Deferrals (Calendar Year 2017)

Line No.		Source	Jan-17
	(a)	(b)	(c)
	Residential Group		
1	Actual Customers	Revenue System	212,134
2	Monthly Decoupled Revenue per Customer	Attachment 4, Page 3	$88.32
3	Decoupled Revenue	(1) x (2)	$ 18,736,261
4	Actual Base Rate Revenue	Revenue System	$ 29,977,440
5	Actual Basic Charge Revenue	Revenue System	$ 1,836,153
6	Acutal Usage (kWhs)	Revenue System	330,420,975
7	Retail Revenue Credit ($/kWh)	Attachment 4, Page 1	$ 0.01641
8	Variable Power Supply Payments	(6) x (7)	$ 5,422,208
9	Customer Decoupled Payments	(4) - (5) -(8)	$ 22,719,078
	Residential Revenue Per Customer Received		$107.10
10	Deferral - Surcharge (Rebate)	(3) - (9)	$ (3,982,817)
11	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 182,732
		FERC Rate	3.50%
12	Interest on Deferral	Avg Balance Calc	$ (5,542)
	Monthly Residential Deferral Totals		**$ (3,805,628)**
13	Cumulative Residential Deferral Surcharge/(Rebate) Balance	Σ((10) ~ (12))	$ (3,805,628)
	Non-Residential Group		
14	Actual Customers	Revenue System	35,883
15	Monthly Decoupled Revenue per Customer	Attachment 4, Page 3	$362.51
16	Decoupled Revenue	(14) x (15)	$ 13,008,001
17	Actual Base Rate Revenue	Revenue System	$ 18,192,580
18	Actual Basic Charge Revenue	Revenue System	$ 1,566,351
19	Acutal Usage (kWhs)	Revenue System	185,988,820
20	Retail Revenue Credit ($/kWh)	Attachment 4, Page 1	$ 0.01641
21	Variable Power Supply Payments	(19) x (20)	$ 3,052,077
22	Customer Decoupled Payments	(17) - (18) -(21)	$ 13,574,152
	Non-Residential Revenue Per Customer Received		$378.29
23	Deferral - Surcharge (Rebate)	(16) - (22)	$ (566,151)
24	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 25,975
		FERC Rate	3.50%
25	Interest on Deferral	Avg Balance Calc	$ (788)
	Monthly Non-Residential Deferral Totals		**$ (540,964)**
26	Cumulative Non-Residential Deferral Surcharge/(Rebate) Balance	Σ((23) ~ (25))	$ (540,964)
27	**Total Cumulative Electric Deferral**	**(13) + (26)**	$ (4,346,591)

Table 1-41. 2017 Development of Electric Deferral

Avista Utilities
Decoupling Mechanism - UE-150204 Base effective 1/11/2016
Development of WA Electric Deferrals (Calendar Year 2017)

Line No.		Source	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Residential Group														
1	Actual Customers	Revenue System	212,134	212,059	212,618	212,018	211,258	211,830	211,439	212,411	212,339	213,798	213,856	214,177	2,549,937
2	Monthly Decoupled Revenue per Customer	Attachment 4, Page 3	$88.32	$72.17	$70.97	$53.46	$51.70	$45.97	$47.58	$56.26	$45.47	$54.00	$65.98	$86.05	$737.94
3	Decoupled Revenue	(1) x (2)	$ 18,736,261	$ 15,303,273	$ 15,089,955	$ 11,335,418	$ 10,921,817	$ 9,738,060	$ 10,060,491	$ 11,949,512	$ 9,655,366	$ 11,545,452	$ 14,110,432	$ 18,430,720	$ 156,876,758
4	Actual Base Rate Revenue	Revenue System	$ 29,977,440	$ 21,701,036	$ 19,217,979	$ 15,485,303	$ 14,335,482	$ 13,375,308	$ 17,431,399	$ 18,289,235	$ 14,321,080	$ 14,347,883	$ 18,951,062	$ 24,646,420	$ 222,079,628
5	Actual Basic Charge Revenue	Revenue System	$ 1,836,153	$ 1,834,377	$ 1,843,863	$ 1,840,658	$ 1,850,433	$ 1,866,107	$ 1,855,734	$ 1,869,014	$ 1,855,882	$ 1,860,480	$ 1,856,154	$ 1,857,488	$ 22,226,341
6	Actual Usage (kWhs)	Revenue System	330,420,975	242,845,820	216,778,430	174,126,974	161,673,824	149,145,253	195,746,292	206,172,696	161,177,614	163,829,516	214,624,109	275,751,737	2,492,293,240
7	Retail Revenue Credit ($/kWh)	Attachment 4, Page 1	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	
8	Variable Power Supply Payments	(6) x (7)	$ 5,422,208	$ 3,985,100	$ 3,557,334	$ 2,857,424	$ 2,653,067	$ 2,447,474	$ 3,212,197	$ 3,383,294	$ 2,644,925	$ 2,688,442	$ 3,521,982	$ 4,525,086	$ 40,898,532
9	Customer Decoupled Payments	(4) - (5) -(8)	$ 22,719,078	$ 15,881,560	$ 13,816,783	$ 10,787,221	$ 9,831,982	$ 9,061,727	$ 12,363,469	$ 13,036,927	$ 9,820,274	$ 9,798,961	$ 13,572,927	$ 18,263,846	$ 158,954,755
	Residential Revenue Per Customer Received		$107.10	$74.89	$64.98	$50.88	$46.54	$42.78	$58.47	$61.38	$46.25	$45.83	$63.47	$85.27	
10	Deferral - Surcharge (Rebate)	(3) - (9)	$ (3,982,817)	$ (578,287)	$ 1,273,172	$ 548,197	$ 1,089,836	$ 676,333	$ (2,302,978)	$ (1,087,415)	$ (164,908)	$ 1,746,491	$ 537,505	$ 166,874	$ (2,077,997)
11	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 182,732	$ 26,532	$ (58,413)	$ (25,151)	$ (50,002)	$ (31,030)	$ 105,661	$ 49,891	$ 7,566	$ (80,129)	$ (24,661)	$ (7,656)	$ 95,338
		FERC Rate	3.50%	3.50%	3.50%	3.71%	3.71%	3.71%	3.96%	3.96%	3.96%	4.21%	4.21%	4.21%	
12	Interest on Deferral	Avg Balance Calc	$ (5,542)	$ (11,904)	$ (10,972)	$ (8,978)	$ (6,590)	$ (4,005)	$ (6,849)	$ (12,209)	$ (14,221)	$ (12,522)	$ (8,743)	$ (7,595)	$ (110,132)
	Monthly Residential Deferral Totals		**$ (3,805,628)**	**$ (563,660)**	**$ 1,203,787**	**$ 514,068**	**$ 1,033,244**	**$ 641,298**	**$ (2,204,166)**	**$ (1,049,734)**	**$ (171,563)**	**$ 1,653,840**	**$ 504,101**	**$ 151,623**	**$ (2,092,790)**
13	Cumulative Deferral (Rebate)/Surcharge Balance	Σ((10) ~ (12))	$ (3,805,628)	$ (4,369,287)	$ (3,165,501)	$ (2,651,433)	$ (1,618,188)	$ (976,891)	$ (3,181,057)	$ (4,230,791)	$ (4,402,355)	$ (2,748,514)	$ (2,244,413)	**$ (2,092,790)**	
	Non-Residential Group														
14	Actual Customers	Revenue System	35,883	35,789	36,027	35,857	35,704	36,104	35,886	36,188	36,104	36,212	35,948	36,223	431,925
15	Monthly Decoupled Revenue per Customer	Attachment 4, Page 3	$362.51	$368.65	$345.36	$343.55	$369.91	$385.27	$416.90	$389.60	$372.63	$380.49	$350.02	$369.70	$4,454.59
16	Decoupled Revenue	(14) x (15)	$ 13,008,001	$ 13,193,484	$ 12,442,315	$ 12,318,697	$ 13,207,236	$ 13,909,650	$ 14,961,052	$ 14,098,703	$ 13,453,579	$ 13,778,285	$ 12,582,387	$ 13,391,801	$ 160,345,191
17	Actual Base Rate Revenue	Revenue System	$ 18,192,580	$ 17,500,279	$ 17,252,313	$ 16,052,469	$ 16,625,114	$ 17,868,330	$ 19,688,932	$ 20,070,393	$ 17,360,373	$ 17,081,518	$ 17,352,968	$ 18,278,019	$ 213,323,288
18	Actual Basic Charge Revenue	Revenue System	$ 1,566,351	$ 1,568,279	$ 1,574,252	$ 1,569,821	$ 1,564,851	$ 1,581,612	$ 1,566,310	$ 1,584,153	$ 1,577,422	$ 1,573,389	$ 1,578,531	$ 1,581,325	$ 18,886,297
19	Actual Usage (kWhs)	Revenue System	185,988,820	176,601,249	174,880,403	161,375,406	169,307,988	184,519,265	206,968,295	209,585,575	179,036,918	172,986,219	173,841,003	191,504,968	2,186,596,108
20	Retail Revenue Credit ($/kWh)	Attachment 4, Page 1	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	$ 0.01641	
21	Variable Power Supply Payments	(19) x (20)	$ 3,052,077	$ 2,898,026	$ 2,869,787	$ 2,648,170	$ 2,778,344	$ 3,027,961	$ 3,396,350	$ 3,439,299	$ 2,937,996	$ 2,838,704	$ 2,852,731	$ 3,142,597	$ 35,882,042
22	Customer Decoupled Payments	(17) - (18) -(21)	$ 13,574,152	$ 13,033,973	$ 12,808,273	$ 11,834,477	$ 12,281,918	$ 13,258,757	$ 14,726,273	$ 15,046,941	$ 12,844,955	$ 12,669,425	$ 12,921,706	$ 13,554,097	$ 158,554,949
	Non-Residential Revenue Per Customer Received		$378.29	$364.19	$355.52	$330.05	$343.99	$367.24	$410.36	$415.80	$355.78	$349.87	$359.46	$374.18	
23	Deferral - Surcharge (Rebate)	(16) - (22)	$ (566,151)	$ 159,511	$ (365,958)	$ 484,220	$ 925,318	$ 650,893	$ 234,780	$ (948,238)	$ 608,624	$ 1,108,860	$ (339,319)	$ (162,296)	$ 1,790,242
24	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 25,975	$ (7,318)	$ 16,790	$ (22,216)	$ (42,454)	$ (29,863)	$ (10,772)	$ 43,505	$ (27,924)	$ (50,874)	$ 15,568	$ 7,446	$ (82,136)
		FERC Rate	3.50%	3.50%	3.50%	3.71%	3.71%	3.71%	3.96%	3.96%	3.96%	4.21%	4.21%	4.21%	
25	Interest on Deferral	Avg Balance Calc	$ (788)	$ (1,356)	$ (1,647)	$ (1,577)	$ 498	$ 2,824	$ 4,418	$ 3,309	$ 2,785	$ 5,846	$ 7,154	$ 6,340	$ 27,805
	Monthly Non-Residential Deferral Totals		**$ (540,964)**	**$ 150,837**	**$ (350,815)**	**$ 460,427**	**$ 883,362**	**$ 623,854**	**$ 228,426**	**$ (901,424)**	**$ 583,485**	**$ 1,063,831**	**$ (316,598)**	**$ (148,510)**	**$ 1,735,911**
26	Cumulative Deferral (Rebate)/Surcharge Balance	Σ((23) ~ (25))	$ (540,964)	$ (390,127)	$ (740,942)	$ (280,515)	$ 602,847	$ 1,226,701	$ 1,455,126	$ 553,702	$ 1,137,188	$ 2,201,019	$ 1,884,421	**$ 1,735,911**	
25	**Total Cumulative Deferral (Rebate)/Surcharge Balance**	**(13) + (26)**	$ (4,346,591)	$ (4,759,414)	$ (3,906,443)	$ (2,931,948)	$ (1,015,341)	$ 249,810	$ (1,725,931)	$ (3,677,089)	$ (3,265,167)	$ (547,495)	$ (359,992)	**$ (356,879)**	

Natural Gas Group 1 (Residential) and Group 2 (Non-Residential)

For natural gas, following steps in Schedule 175A, *Decoupled Revenue per Customer (by Rate Group)* is developed. Calculation of Decoupled Revenue per Customer (by Rate Group) is specified in seven steps in Schedule 175A. These steps are implemented in Table 1-42 and Table 1-43. Monthly Decoupled Revenue per Customer for Group 1: Residential and Group 2: Non-Residential are then used to develop the *Monthly Decoupling Deferral* for natural gas, following the steps in Schedule 175B.

Schedule 175A – Decoupled Revenue per Customer

Step 1: Step 1 is to enter the Total Normalized Revenue, which is equal to the final approved base rate revenue approved in the Company's last general rate case, individually for each rate class. Table 1-42, Line 1 shows initial 12 ME September 2014 Total Normalized Net Revenue. In addition, Line 2 shows Allowed Revenue Increase. The sum of Line 1 and Line 2 is shown on Line 3 as the Total Rate Revenue (January 11, 2016). This corresponds to the full value specified in Step 1.

Step 2: Step 2 is to determine the Variable Gas Supply Revenue. This Variable Gas Supply Revenue is shown on Line 6. It the product of Normalized Therms by rate schedule from the last approved general rate case from Line 4 times the PGA Rates from Line 5.

Step 3: Step 3 is to determine Delivery Revenue, which is entered on Line 7. To determine the Delivery Revenue, the Variable Gas Supply Revenue is subtracted from the Total Normalized Revenue.

Step 4: Step 4 is to calculate the Basic Charge Revenue. Because the decoupling mechanism only tracks revenue that varies with customer energy usage, revenue from Fixed Charges is removed. It is the product of the number of Customer Bills in the test period on Line 8 times the Allowed Basic Charges (Line 9). The result, Basic Charge Revenue, is shown on Line 10.

Step 5: Determine the Allowed Decoupled Revenue. The Allowed Decoupled Revenue is equal to the Delivery (from Line 7) minus the Basic Charge Revenue (Line 10). The resulting Decoupled Revenue is shown on Line 11.

Step 6: In Step 6, Decoupled Revenue from Line 11 is put on a per customer basis. The Decoupled Revenue (by Rate Group) is divided by the approved Test Year number of customers (by Rate Group). This determines the annual Allowed Decoupled Revenue per Customer (by Rate Group) as shown in Table 1-43.

Step 7: Step 7 is different from the other steps because it converts the annual Allowed Decoupled Revenue per Customer (by Rate Group) into monthly values. The assignment of monthly values is carried out by first calculating the distribution of monthly therm use in the test year. This calculation is shown in Table 1-44.

In Table 1-44, therm use for Group 1 (Residential) for test year is shown in Line 4 and for Group 2 (Non-Residential) in Line 8. Both monthly therm values and the annual therm values are shown. Below the monthly values, percentages (Lines 5 and 9) are shown. Lines 14 and 18 show the use of these percentages, applied to annual Allowed Decoupled Revenue per Customer (by Rate Group) to generate monthly values.

These monthly values are then taken forward to be used in the implementation of Schedule 175B.

Table 1-42. 2017 Development of Natural Gas Decoupled Revenue per Customer

Natural Gas Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Natural Gas

	TOTAL	RESIDENTIAL SCHEDULE 101	GENERAL SVC. SCH. 111	LG. GEN. SVC. SCH. 121	INTERRUPTIBLE SCH 131	SCHEDULES 112, 122, 132	SCHEDULES 146 & 148
1 Total Normalized 12 ME Sept 2014 Revenue	$ 146,557,000	$ 106,954,000	$ 31,478,000	$ 2,973,000	$ -	$ 968,000	$ 4,184,000
2 Allowed Revenue Increase (Attachment 2)	$ 10,824,000	$ 8,398,000	$ 1,867,000	$ 161,000	$ -	$ 40,000	$ 358,000
3 Total Rate Revenue (January 11, 2016)	$ 157,381,000	$ 115,352,000	$ 33,345,000	$ 3,134,000	$ -	$ 1,008,000	$ 4,542,000
4 Normalized Therms (12ME Sept 2014 Test Year)	255,186,931	120,721,607	47,537,282	5,069,530	-	1,781,211	80,077,301
5 11/1/2015 Schedule 150 PGA Rates		$ 0.38907	$ 0.38166	$ 0.37077	$ 0.33645		
6 Variable Gas Supply Revenue	$ 66,991,864	$ 46,969,156	$ 18,143,079	$ 1,879,630	$ -		
7 Delivery Revenue (Ln 3 - Ln 6)	$ 84,839,136	$ 68,382,844	$ 15,201,921	$ 1,254,370	$ -		
8 Customer Bills (12ME Sept 2014 Test Year)	1,819,516	1,787,943	30,697	312	0	48	516
9 Allowed Basic Charges		$9.00	$101.44	$252.28	$0.00		
10 Basic Charge Revenue (Ln 8 * Ln 9)	$ 19,284,102	$ 16,091,487	$ 3,113,904	$ 78,711	$ -		
						Excluded From Decoupling	
11 Decoupled Revenue	$ 65,555,034	$ 52,291,357	$ 12,088,017	$ 1,175,659	$ -		
		Residential	Non-Residential Group				
12 Average Number of Customers (Line 8 / 12)		148,995	2,584				
13 Annual Therms		120,721,607	52,606,812				
14 Basic Charge Revenues		$ 16,091,487	$ 3,192,615				
15 Customer Bills		1,787,943	31,009				
16 Average Basic Charge		$9.00	$102.96				

Table 1-43. 2017 Natural Gas Decoupled Revenue per Customer

Line No.	Natural Gas Decoupling Mechanism Development of Decoupled Revenue Per Customer - Natural Gas	Source	Residential	Non-Residential Schedules*
	(a)	(b)	(c)	(d)
1	Decoupled Revenues	Attachment 5, Page 1	$ 52,291,357	$ 13,263,676
2	Test Year # of Customers 12 ME 09.2014	Revenue Data	148,995	2,584
3	Decoupled Revenue Per Customer	(1) / (2)	$ 350.96	$ 5,132.84
	*Sales Schedules 111, 121, 131.			
		Revenues		
		From Revenue Per Customer	$ 52,291,373	$ 13,263,686
		From Basic Charges	$ 16,091,487	$ 3,192,615
		From Gas Supply	$ 46,969,156	$ 20,022,709
		Total	$ 115,352,016	$ 36,479,010

Table 1-44. 2017 Development of Monthly Natural Gas Decoupled Revenue per Customer

Avista Utilities
Natural Gas Decoupling Mechanism
'Development of Monthly Decoupled Revenue Per Customer - Natural Gas

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1															
2	**Natural Gas Delivery Volume**														
3	*Residential*														
4	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	21,149,989	17,496,849	14,113,448	7,866,788	4,895,089	2,998,022	2,095,088	2,047,777	2,727,612	8,666,827	14,928,966	21,735,152	120,721,607
5	- % of Annual Total	% of Total	17.52%	14.49%	11.69%	6.52%	4.05%	2.48%	1.74%	1.70%	2.26%	7.18%	12.37%	18.00%	100.00%
6															
7	*Non-Residential Sales**														
8	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	7,724,199	6,497,617	5,741,989	3,833,669	3,002,355	2,283,253	1,727,751	1,696,708	2,070,681	4,248,069	5,991,318	7,789,203	52,606,812
9	- % of Annual Total	% of Total	14.68%	12.35%	10.91%	7.29%	5.71%	4.34%	3.28%	3.23%	3.94%	8.08%	11.39%	14.81%	100.00%
10															
11	**Monthly Decoupled Revenue Per Customer ("RPC")**														
12	*Residential*														
13	-UG-150205 Decoupled RPC	Attachment 5, P. 2 L. 3													$ 350.96
14	-Monthly Decoupled RPC	(5) x (13)	$ 61.49	$ 50.87	$ 41.03	$ 22.87	$ 14.23	$ 8.72	$ 6.09	$ 5.95	$ 7.93	$ 25.20	$ 43.40	$ 63.19	$ 350.96
15															
16	*Non-Residential Sales**														
17	-UG-150205 Decoupled RPC	Attachment 5, P. 2 L. 3													$ 5,132.84
18	-Monthly Decoupled RPC	(9) x (17)	$ 753.65	$ 633.97	$ 560.25	$ 374.05	$ 292.94	$ 222.78	$ 168.58	$ 165.55	$ 202.04	$ 414.48	$ 584.57	$ 759.99	$ 5,132.84
19															
20	*Sales Schedules 111, 121, 131.														

Schedule 175B – Monthly Decoupling Deferral

Schedule 175B specifies the method for developing the *Monthly Decoupling Deferral* for natural gas service. For Group 1 (Residential), the calculation of the monthly decoupling deferral for January 2017 is shown in Table 1-45.[20] In the full version of this table (Table 1-46), the monthly decoupling deferral amounts across 2017 sum to the annual total decoupling deferral for 2017. As shown in Table 1-46, the annual total decoupling deferral for Residential natural gas is negative $1,972,082. The annual total decoupling deferral for Non-Residential natural gas is $840,286.

The individual steps in the Schedule 175B procedure are shown in both Table 1-45 and Table 1-46.

Step 1: Step 1 is to determine the actual number of customers each month. For Group 1 (Residential), this is shown in Line 1 of Table 1-45 and Table 1-46. For Group 2 (Non-Residential), this is shown in Line 11.

Step 2: Step 2 is to multiply the actual number of customers (Line 1 for Residential; Line 11 for Non-Residential) by the applicable monthly Allowed Decoupled Revenue per Customer (Line 2 for Residential; Line 12 for Non-Residential), which was developed in the Schedule 175A procedure. Allowed Decoupled Revenue for Residential is shown on Line 3. Allowed Decoupled Revenue for Non-Residential is shown on Line 13.

Step 3: Step 3 determines Actual Revenue collected. For Residential, this is shown on Line 4. For Non-Residential Actual Base Rate Revenue (Excluding Gas Costs) is shown on Line 14.

Step 4: Step 4 calculates the amount of Actual Fixed Charge Revenues included in Actual Revenues. This is shown on Line 5 for Residential and on Line 15 for Non-Residential.

Step 5: In Step 5, Actual Fixed Charge Revenue (Line 5 for Residential; Line 15 for Non-Residential) is subtracted from Actual Revenue (Line 4 for Residential; Line 14 for Non-Residential). The result is shown on Line 6 for Residential and on Line 16 for Non-Residential. At this point in the calculation all fixed charges have been removed, leaving only variable charges. In Table 1-46 this is shown as both Customer Decoupled Payments in total and as Revenue per Customer received.

Step 6: In Step 6, the difference between the Actual Decoupled Revenue from Step 5 (Line 6 for Residential and Line 16 for Non-Residential) and the Allowed Decoupled Revenue from Step 2 (Line 3 for Residential and Line 13 for Non-Residential) is calculated. The resulting balance (Lines 7, 8 and 9 for Residential and Lines 17, 18 and 19 for Non-Residential) is the Deferral Total.

Within Step 6, Line 7 for Residential and Line 17 for Non-Residential is the Direct Deferral (which is either a Surcharge or a Rebate).

[20] Only one month is shown here to keep the table readable on the page.

Revenue Related Expense are stated on Line 8 for Residential and Line 18 for Non-Residential. Below this, the Federal Energy Regulatory Commission rate of interest (FERC Rate) is stated. Then, the result of the Average Balance Calculation is stated.

Line 9 (for Residential) and Line 19 (for Non-Residential) show the amount of Interest on Deferral. Below this, the result is the Deferral Totals.

For Residential, the Deferral Total has is a negative $1,972,082. This result is reported by Avista on Page 2 of 5 in the Natural Gas letter of transmittal from Patrick Ehrbar to the Commission dated August 17, 2018. For Non-Residential, the Deferral Total is $840,286. This result is reported by Avista on Page 3 of 5 in the Natural Gas letter of transmittal regarding Tariff WN U-29, Natural Gas Service, Natural Gas Decoupling Rate Adjustment in Docket Number UG-140189 from Patrick Ehrbar to the Commission dated August 17, 2018.

Table 1-45. 2017 Natural Gas Deferral Calculations

Avista Utilities
Decoupling Mechanism - UG-150205 Base effective 1/11/2016
Development of WA Natural Gas Deferrals (Calendar Year 2017)

Line No.		Source	Pro Rated Jan-17
	(a)	(b)	(c)
	Residential Group		
1	Actual Customers	Revenue System	156,425
2	Monthly Decoupled Revenue per Customer	Attachment 5, Page 3	$61.49
3	Decoupled Revenue	(1) x (2)	$ 9,618,092
	Actual Usage (informational only)	Revenue System	27,300,256
4	Actual Base Rate Revenue (Excludes Gas Costs)	Revenue System	$ 14,178,143
5	Actual Fixed Charge Revenue	Revenue System	$ 1,422,936
6	Customer Decoupled Payments	(4) - (5)	$ 12,755,207
	Residential Revenue Per Customer Received		$81.54
7	Deferral - Surcharge (Rebate)	(3) - (6)	$ (3,137,115)
8	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 143,266
		FERC Rate	3.50%
9	Interest on Deferral	Avg Balance Calc	$ (4,366)
	Monthly Residential Deferral Totals		**$ (2,998,215)**
10	Cumulative Residential Deferral Surcharge/(Rebate) Balance	Σ((7) ~ (9))	$ (2,998,215)
	Non-Residential Group		
11	Actual Customers	Revenue System	2,866
12	Monthly Decoupled Revenue per Customer	Attachment 5, Page 3	$753.65
13	Decoupled Revenue	(11) x (12)	$ 2,159,958
	Actual Usage (informational only)		9,022,828
14	Actual Base Rate Revenue (Excludes Gas Costs)	Revenue System	$ 2,687,109
15	Actual Fixed Charge Revenue	Revenue System	$ 319,691
16	Customer Decoupled Payments	(14) - (15)	$ 2,367,417
	Non-Residential Revenue Per Customer Received		$826.04
17	Deferral - Surcharge (Rebate)	(13) - (16)	$ (207,459)
18	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 9,474
		FERC Rate	3.50%
19	Interest on Deferral	Avg Balance Calc	$ (289)
	Monthly Non-Residential Deferral Totals		**$ (198,274)**
20	Cumulative Non-Residential Deferral Surcharge/(Rebate) Balance	Σ((17) ~ (19))	$ (198,274)
21	**Total Cumulative Natural Gas Deferral**	**(10) + (20)**	$ (3,196,489)

Table 1-46. 2017 Development of Natural Gas Deferral

Avista Utilities
Decoupling Mechanism - UG-150205 Base effective 1/11/2016
Development of WA Natural Gas Deferrals (Calendar Year 2017)

Line No.		Source	Pro Rated Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017 YTD Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Residential Group														
1	Actual Customers	Revenue System	156,425	156,620	156,919	156,785	156,510	157,170	157,080	157,589	157,973	158,696	159,255	159,738	1,890,760
2	Monthly Decoupled Revenue per Customer	Attachment 5, Page 3	$61.49	$50.87	$41.03	$22.87	$14.23	$8.72	$6.09	$5.95	$7.93	$25.20	$43.40	$63.19	$29.28
3	Decoupled Revenue	(1) x (2)	$ 9,618,092	$ 7,966,722	$ 6,438,449	$ 3,585,705	$ 2,227,282	$ 1,369,863	$ 956,744	$ 938,169	$ 1,252,674	$ 3,998,515	$ 6,911,868	$ 10,093,541	$ 55,357,624
	Actual Usage (informational only)	Revenue System	27,300,256	19,186,624	14,338,876	9,656,822	4,949,757	2,545,688	2,072,779	2,083,100	3,151,156	8,849,788	14,859,437	22,788,639	
4	Actual Base Rate Revenue (Excludes Gas Costs)	Revenue System	$ 14,178,143	$ 9,916,592	$ 7,596,509	$ 5,392,471	$ 3,376,968	$ 2,365,888	$ 2,319,586	$ 2,360,614	$ 2,703,609	$ 4,991,030	$ 7,735,067	$ 11,662,425	
5	Actual Fixed Charge Revenue	Revenue System	$ 1,422,936	$ 1,424,844	$ 1,431,234	$ 1,430,091	$ 1,435,815	$ 1,447,083	$ 1,441,215	$ 1,447,191	$ 1,446,363	$ 1,450,971	$ 1,453,338	$ 1,455,831	
6	Customer Decoupled Payments	(4) - (5)	$ 12,755,207	$ 8,491,748	$ 6,165,275	$ 3,962,380	$ 1,941,153	$ 918,805	$ 878,371	$ 913,423	$ 1,257,246	$ 3,540,059	$ 6,281,729	$ 10,206,594	$ 57,311,991
	Residential Revenue Per Customer Received		$81.54	$54.22	$39.29	$25.27	$12.40	$5.85	$5.59	$5.80	$7.96	$22.31	$39.44	$63.90	$30.31
7	Deferral - Surcharge (Rebate)	(3) - (6)	$ (3,137,115)	$ (525,026)	$ 273,174	$ (376,675)	$ 286,130	$ 451,058	$ 78,373	$ 24,746	$ (4,572)	$ 458,456	$ 630,139	$ (113,054)	$ (1,954,367)
8	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 143,266	$ 23,977	$ (12,475)	$ 17,202	$ (13,067)	$ (20,599)	$ (3,579)	$ (1,130)	$ 209	$ (20,937)	$ (28,777)	$ 5,163	$ 89,252
		FERC Rate	3.50%	3.50%	3.50%	3.71%	3.71%	3.71%	3.96%	3.96%	3.96%	4.21%	4.21%	4.21%	
9	Interest on Deferral	Avg Balance Calc	$ (4,366)	$ (9,475)	$ (9,854)	$ (10,628)	$ (10,794)	$ (9,740)	$ (9,595)	$ (9,464)	$ (9,464)	$ (9,335)	$ (7,545)	$ (6,706)	$ (106,967)
	Monthly Residential Deferral Totals		**$ (2,998,215)**	**$ (510,524)**	**$ 250,845**	**$ (370,101)**	**$ 262,268**	**$ 420,718**	**$ 65,199**	**$ 14,151**	**$ (13,827)**	**$ 428,184**	**$ 593,816**	**$ (114,597)**	**$ (1,972,082)**
10	Cumulative Residential Deferral Surcharge/(Rebate) Balance	Σ((7) ~ (9))	$ (2,998,215)	$ (3,508,740)	$ (3,257,895)	$ (3,627,996)	$ (3,365,728)	$ (2,945,009)	$ (2,879,810)	$ (2,865,659)	$ (2,879,486)	$ (2,451,302)	$ (1,857,485)	**$ (1,972,082)**	
	Non-Residential Group														
11	Actual Customers	Revenue System	2,866	2,902	2,916	2,906	2,896	2,946	2,913	2,937	2,920	2,927	2,936	2,948	35,013
12	Monthly Decoupled Revenue per Customer	Attachment 5, Page 3	$753.65	$633.97	$560.25	$374.05	$292.94	$222.78	$168.58	$165.55	$202.04	$414.48	$584.57	$759.99	$427.33
13	Decoupled Revenue	(11) x (12)	$ 2,159,958	$ 1,839,786	$ 1,633,675	$ 1,086,991	$ 848,352	$ 656,300	$ 491,063	$ 486,213	$ 589,945	$ 1,213,193	$ 1,716,304	$ 2,240,455	$ 14,962,237
	Actual Usage (informational only)		9,022,828	7,657,412	5,938,084	4,309,520	2,727,620	2,167,431	1,721,383	1,755,660	2,513,871	3,878,272	5,784,096	8,208,132	
14	Actual Base Rate Revenue (Excludes Gas Costs)	Revenue System	$ 2,687,109	$ 2,288,757	$ 1,839,236	$ 1,400,402	$ 968,527	$ 804,792	$ 687,977	$ 700,180	$ 887,558	$ 1,254,376	$ 1,801,576	$ 2,405,752	
15	Actual Fixed Charge Revenue	Revenue System	$ 319,691	$ 298,237	$ 299,449	$ 298,624	$ 298,968	$ 304,063	$ 299,901	$ 302,515	$ 300,448	$ 300,605	$ 332,404	$ 284,936	
16	Customer Decoupled Payments	(14) - (15)	$ 2,367,417	$ 1,990,520	$ 1,539,787	$ 1,101,779	$ 669,559	$ 500,729	$ 388,076	$ 397,664	$ 587,110	$ 953,771	$ 1,469,172	$ 2,120,816	$ 14,086,400
	Non-Residential Revenue Per Customer Received		$826.04	$685.91	$528.05	$379.14	$231.20	$169.97	$133.22	$135.40	$201.07	$325.85	$500.40	$719.41	$402.32
17	Deferral - Surcharge (Rebate)	(13) - (16)	$ (207,459)	$ (150,734)	$ 93,888	$ (14,788)	$ 178,794	$ 155,571	$ 102,987	$ 88,549	$ 2,835	$ 259,422	$ 247,132	$ 119,639	$ 875,837
18	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 9,474	$ 6,884	$ (4,288)	$ 675	$ (8,165)	$ (7,105)	$ (4,703)	$ (4,044)	$ (129)	$ (11,847)	$ (11,286)	$ (5,464)	$ (39,998)
		FERC Rate	3.50%	3.50%	3.50%	3.71%	3.71%	3.71%	3.96%	3.96%	3.96%	4.21%	4.21%	4.21%	
19	Interest on Deferral	Avg Balance Calc	$ (289)	$ (788)	$ (869)	$ (808)	$ (568)	$ (77)	$ 325	$ 628	$ 774	$ 1,264	$ 2,117	$ 2,738	$ 4,447
	Monthly Non-Residential Deferral Totals		**$ (198,274)**	**$ (144,639)**	**$ 88,731**	**$ (14,920)**	**$ 170,061**	**$ 148,390**	**$ 98,609**	**$ 85,133**	**$ 3,479**	**$ 248,839**	**$ 237,963**	**$ 116,914**	**$ 840,286**
20	Cumulative Non-Residential Deferral Surcharge/(Rebate) Balance	Σ((17) ~ (19))	$ (198,274)	$ (342,912)	$ (254,181)	$ (269,101)	$ (99,041)	$ 49,349	$ 147,958	$ 233,091	$ 236,570	$ 485,410	$ 723,372	**$ 840,286**	
21	**Total Cumulative Natural Gas Deferral**	**(10) + (20)**	$ (3,196,489)	$ (3,851,652)	$ (3,512,076)	$ (3,897,097)	$ (3,464,769)	$ (2,895,660)	$ (2,731,852)	$ (2,632,568)	$ (2,642,916)	$ (1,965,892)	$ (1,134,113)	**$ (1,131,796)**	

2017 Earnings Test

The decoupling mechanism, in Schedules 75D and 175D provides for application of an earnings test,[21] separately for electric and for natural gas.[22]

Schedule 75D – Electric Earnings Test

According to Schedule 75D, the decoupling mechanism for decoupled electric customers is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues and various normalizing adjustments. As shown in Table 1-47, Line 3, the rate of return on a normalized basis in 2017is 7.41%. This exceeds the 7.29% allowed return established by Docket No. UE-150204 (Line 4).[23] The Excess ROR is 0.12%, corresponding to Excess Earnings of $1,852,833 (Line 6). A Conversion Factor is entered on Line 7, which is divided into the Excess Earnings to produce Excess Revenue (Line 8) of $2,986,551. When the 50% Sharing (Line 9) is applied, the Total Earnings Test Sharing for electric is $1,493,276 (Line 10).

Table 1-47. 2017 Electric Earnings Test

2017 Commission Basis Earnings Test for Decoupling		
Line No.		Electric
1	Rate Base	$ 1,513,706,000
2	Net Income	$ 112,202,000
3	Calculated ROR	7.41%
4	Base ROR	7.29%
5	Excess ROR	0.12%
6	Excess Earnings	$ 1,852,833
7	Conversion Factor	0.620392
8	Excess Revenue (Excess Earnings/CF)	$ 2,986,551
9	Sharing %	50%
10	2017 Total Earnings Test Sharing	**$ 1,493,276**

[21] Information on the background of the Earnings Test is limited to information provided in the Tariff. In response to Data Request 092, Avista states that "[t]he calculation of excess earnings was agreed upon as part of the Settlement process in Docket Nos. 140188 and 140189. All information regarding the excess earnings test is included in the Tariff Schedule 75D."

[22] Rate of Return is not related to the operation of the 3% cap. In response to DR 091, Avista states that "Rate of Return (ROR) is net income divided by rate base for a given annual period. The combination of three elements, namely revenues, expenses, and rate base, determine the resulting ROR. Changes to the relationship among all of these elements will impact the actual or normalized actual ROR achieved each year. The 3% cap impacts the timing of amortization of prior year deferred revenue and as such does not impact earnings or rate base during the amortization period because surcharge revenues from customers are offset by deferred revenue amortization for a net income impact of $0 and the deferred revenue on the balance sheet is not included in rate base."

[23] Page 6, Paragraph 5 (Commission Determinations) in Washington Utilities and Transportation Commission v. Avista Corporation dba Avista Utilities, Dockets UE-150204 and UG-150205 (Consolidated), Order 05, Final Order Rejecting Tariff Finding, Accepting Partial Settlement Stipulation, Authorizing Tariff Findings. Service Date January 26, 2016.

The Electric Total Earnings Test Sharing amount is then split between residential and non-residential customer groups in proportion to their contribution to Total Normalized Revenue (Table 1-48). The split is 51.09% Electric Residential and 48.91% Electric Non-Residential.

The dollar values for the split are $762,867 Electric Residential (Line 14) and $730,409 Electric Non-Residential (Line 15). These values are adjusted to remove various revenue related expenses by dividing them by the Gross Up Factor derived in Table 1-49 (1.047725). The final values for the Electric Earnings Test are $728,117 for Residential Electric and $697,138 for Non-Residential Electric. These values are shown on Line 14 and Line 15, respectively, in Table 1-48. These are also reported on Page 2 of 5 (Residential) through Page 3 of 5 (Non-Residential) of the Letter of Transmittal from Patrick Ehrbar to the Commission for the Electric Decoupling Rate Adjustment, Tariff WN U-28, Electric Service, dated August 17, 2018, in Docket Number UE-140188.

Table 1-48. 2017 Electric Earnings Test Sharing Adjustment

	Revenue From 2017 Normalized Loads and Customers at Present Billing Rates		
11	Residential Revenue	$ 231,219,047	51.09%
12	Non-Residential Revenue	$ 221,381,435	48.91%
13	Total Normalized Revenue	$ 452,600,482	100.00%
	Earnings Test Sharing Adjustment	Gross Revenue Adjustment	Net of Revenue Related Expenses
14	Residential	$ 762,867	$ 728,117
15	Non-Residential	$ 730,409	$ 697,138
16	Total	$ 1,493,276	$ 1,425,255

Table 1-49. 2017 Derivation of Electric Gross Up Factor and Revenue Conversion Factor

Line No.	Description	Factor
1	**Revenues**	*1.000000*
	Expense:	
2	Uncollectibles	*0.005011*
3	Commission Fees	*0.002000*
4	Washington Excise Tax	*0.038540*
5	Total Expense	*0.045551*
6	Net Operating Income Before FIT	*0.954449*
7	Federal Income Tax @ 35%	*0.334057*
8	**REVENUE CONVERSION FACTOR**	*0.620392*
9	Gross Up Factor	1.047725
2017 Commission Basis Conversion Factor		

Schedule 175D – Natural Gas Earnings Test

According to Schedule 175D, the decoupling mechanism for natural gas is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues and various normalizing adjustments. As shown in Table 1-50. the rate of return on a normalized basis in 2017 is 8.32%. This is more than the 7.29% allowed return (Line 4). The Excess ROR is 1.03% (Line 5). The dollar value of Excess Earnings is $3,226,615. This is adjusted for various revenue expenses by dividing by the Conversion Factor (0.620530) given in Line 7 for Excess Revenue of $5,199,773 as shown in Line 8.

Table 1-50. 2017 Natural Gas Earnings Test

	2017 Commission Basis Earnings Test for Decoupling		
Line No.			Natural Gas
1	Rate Base	$	313,174,000
2	Net Income	$	26,057,000
3	Calculated ROR		8.32%
4	Base ROR		7.29%
5	Excess ROR		1.03%
6	Excess Earnings	$	3,226,615
7	Conversion Factor		0.620530
8	Excess Revenue (Excess Earnings/CF)	$	5,199,773
9	Sharing %		50%
10	2017 Total Earnings Test Sharing	**$**	**2,599,887**

With the Sharing percentage set at 50%, the 2017 Total Earnings Test Sharing is $2,599,887 (Line 10). The Conversion Factor on Line 7 is developed in Table 1-51.

Table 1-51. 2017 Derivation of Gross Up Factor and Revenue Conversion Factor (Natural Gas)

AVISTA UTILITIES
Revenue Conversion Factor
Washington - Gas System
TWELVE MONTHS ENDED December 31, 2017

Line No.	Description	Factor
1	**Revenues**	1.000000
	Expense:	
2	Uncollectibles	0.005012
3	Commission Fees	0.002000
4	Washington Excise Tax	0.038327
5	Total Expense	0.045339
6	Net Operating Income Before FIT	0.954661
7	Federal Income Tax @ 35%	0.334131
8	REVENUE CONVERSION FACTOR	0.620530
9	Gross Up Factor	1.047492

2017 Commission Basis Conversion Factor

The split between Natural Gas Residential and Natural Gas Non-Residential is developed in Table 1-52. The split is modeled on contribution to revenue. Stated in percentage terms, the split is 77.11% Residential and 22.89% Non-Residential (Lines 11 and 12). At the Gross level, the dollar values are $2,004,793 Residential and $595,094 Non-Residential. When expressed net of various revenue expenses (by dividing by the Gross Up Factor from Table 1-52, Line 9, the values are $1,913,898 Natural Gas Residential and $568,113 Natural Gas Non-Residential. These values are also reported Page 2 of 5 for Residential and Page 3 of 5 for Non-Residential in Letter of Transmittal from Patrick Ehrbar to the Commission for Tariff WN U-29, Natural Gas Service, Natural Gas Decoupling Rate Adjustment, dated August 17, 2018 in Docket Number UG-140189.

Table 1-52. 2017 Natural Gas Earnings Test Sharing Adjustment

	Revenue From 2017 Normalized Loads and Customers at Present Billing Rates		
11	Residential Revenue	$ 104,202,001	77.11%
12	Non-Residential Revenue	$ 30,930,843	22.89%
13	Total Normalized Revenue	$ 135,132,844	100.00%
	Earnings Test Sharing Adjustment	Gross Revenue Adjustment	Net of Revenue Related Expenses
14	Residential	$ 2,004,793	$ 1,913,898
15	Non-Residential	$ 595,094	$ 568,113
16	Total	$ 2,599,887	$ 2,482,011

2017 Three-Percent Annual Rate Increase Limitation

Decoupling annual rate adjustment surcharges are subject to a 3% annual rate increase limitation (there is no reciprocal limit on rebate rate adjustments). The test is to divide the *incremental* annual revenue to be collected (proposed surcharge revenue minus present surcharge revenue)[24] by the total "normalized" revenue for the two Rate Groups for the most recent January through December.

Normalized revenue is determined by multiplying the weather-corrected usage for the period by the present rates in effect. If the incremental amount of the proposed surcharge exceeds 3%, only a 3% incremental rate increase will apply. Any remaining deferred revenue will be carried over to the following years.

Schedule 75E – Electric 3% Rate Increase Test

The electric Incremental Surcharge Test is shown in Table 1-53. Following the specifications for the test limits the Residential Surcharge to 3% with the remainder deferred to the following year.

However, division of the Revenue from 2017 Normalized Loads with Customers at Present Billing Rates (Line 1) by the Incremental Decoupling Recovery (Line 6) results in a value of negative 5.78% for Electric Residential and a value of positive 0.14% for Electric Non-Residential (Line 7). Since these values are both less than three percent (3%), no adjustment is necessary for either Electric Residential or for Electric Non-Residential.

Table 1-53. 2017 Electric 3% Incremental Surcharge Test

Line No.	**3% Incremental Surcharge Test**	Residential	Non-Residential
1	Revenue From 2017 Normalized Loads and Customers at Present Billing Rates (Note 1)	$ 231,219,047	$ 221,381,435
2	November 2018 - October 2019 Usage (kWhs)	2,384,168,302	2,168,455,465
3	Proposed Decoupling Recovery Rates	-$0.00116	$0.00054
4	Present Decoupling Surcharge Recovery Rates	$0.00445	$0.00040
5	Incremental Decoupling Recovery Rates	-$0.00561	$0.00014
6	Incremental Decoupling Recovery	$ (13,375,184)	$ 303,584
7	Incremental Surcharge %	**-5.78%**	**0.14%**
8	3% Test Adjustment (Note 2)	$ -	$ -
9	3% Test Rate Adjustment	$0.00000	$0.00000
10	Adjusted Proposed Decoupling Recovery Rates	-$0.00116	$0.00054
11	Adjusted Incremental Decoupling Recovery	$ (13,375,184)	$ 303,584
12	Adjusted Incremental Surcharge %	**-5.78%**	**0.14%**

Notes

(1) Revenue from 2017 normalized loads and customers at present billing rates effective since July 1, 2018.

(2) The carryover balances will differ from the 3% adjustment amounts due to the revenue related expense gross up partially offset by additional interest on the outstanding balance during the amortization period.

[24] To emphasize, this is a test of an incremental surcharge and this test is a key element in the flexibility of Avista's decoupling mechanisms.

Schedule 175E – Natural Gas 3% Rate Increase Test

The natural gas Incremental Surcharge Test is shown in Table 1-54. The test limits the incremental residential and the incremental non-residential surcharge each to 3%.

For both the natural gas residential group and the natural gas non-residential group, the numeric value of the result is negative. Since these values are under 3%, no adjustment is applied. For both groups, there is no deferred revenue carried forward to the following year.

Table 1-54. 2017 Natural Gas 3% Incremental Surcharge Test

Line No.	**3% Incremental Surcharge Test**	Residential	Non-Residential
1	Revenue From 2017 Normalized Loads and Customers at Present Billing Rates (Note 1)	$ 104,202,001	$ 30,930,843
2	November 2018 - October 2019 Usage	126,528,897	59,004,176
3	Proposed Decoupling Recovery Rates	-$0.02720	$0.00691
4	Present Decoupling Surcharge Recovery Rates	$0.05580	$0.03904
5	Incremental Decoupling Recovery Rates	-$0.08300	-$0.03213
6	Incremental Decoupling Recovery	$ (10,501,898)	$ (1,895,804)
7	Incremental Surcharge %	**-10.08%**	**-6.13%**
8	3% Test Adjustment (2)	$ -	$ -
9	3% Test Rate Adjustment	$0.00000	$0.00000
10	Adjusted Proposed Decoupling Recovery Rates	-$0.02720	$0.00691
11	Adjusted Incremental Decoupling Recovery	$ (10,501,898)	$ (1,895,804)
12	Adjusted Incremental Surcharge %	**-10.08%**	**-6.13%**

Notes

(1) Revenue from 2017 normalized loads and customers at present billing rates effective since June 1, 2018.

(2) The carryover balances will differ from the 3% adjustment amounts due to the revenue related expense gross up partially offset by additional interest on the outstanding balance during the amortization period.

Audit Statements: Is the Source Data Credible?

Having reviewed calculations for conformance to Schedule 75 and Schedule 175, the second step in the Task 1 analysis is to validate the general credibility of the test period costs and revenues, balance sheets, load projections, and other company financial data. Since this data was audited by a professional audit team (Deloitte & Touche LLP) that provides an opinion regarding the accuracy of the data, we are relying on their professional opinion to validate the financial integrity of the data.

Attachment A to Avista's Response to H. Gil Peach & Associates Data Request No. 015 provides copies of the Report of the Independent Registered Public Accounting Firm for the Avista Corporation and subsidiaries for calendar years 2015, 2016 and 2017. These opinions are based on certified audits of the company's accounting practices. Each Independent Registered Public Accounting Report expresses an unqualified opinion on the Company's internal control over financial reporting. These opinions validate the data used to implement the Avista electric and natural gas decoupling mechanisms.

The Deloitte & Touche LLP "Report of Independent Registered Public Accounting Firm" for the twelve-month period ending December 31, 2015 is shown as Figure 1-2. Deloitte & Touche LLP also provided their financial audit opinions of Avista's reported financial statements for calendar year 2016 and 2017, as shown in Figure 1-2 and Figure 1-3.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Avista Corporation
Spokane, Washington

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Avista Corporation and subsidiaries at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report, dated February 23, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Seattle, Washington

February 23, 2016

Figure 1-2. 2016 Financial Audit Opinion for Calendar 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM (2016)

To the Board of Directors and
Shareholders of Avista
Corporation
Spokane, Washington

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Avista Corporation and subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report, dated February 21, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Seattle,
Washington
February 21,
2017

Figure 1-3. 2017 Financial Audit Opinion for Calendar 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Avista Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 20, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 20, 2018

We have served as the Company's auditor since 1933.

Figure 1-4. 2018 Financial Audit Opinion for Calendar 2017

Summary - Task 1

Based on our analysis of three years of data, we conclude that Avista has calculated rates and deferrals in accordance with the Commission Order approving the decoupling mechanisms for the first through the third Decoupling Years.

The purpose of the Decoupling Mechanism is to decouple the Company's Commission-authorized revenues from sales, such that the *portion of the Company's fixed costs planned for recovery through volumetric sales and not otherwise recovered from actual energy sales* will be recovered through the mechanism. In decoupling, the revenue requirement for a given year is first set. The portion of fixed costs collected through the fixed portion of customer bills is not included in the analysis. Since volumetric sales fluctuate and may not fully cover the fixed cost component included within the volumetric portions of customer rates, the difference between actual decoupling-related revenue received from customers through volumetric rates, and the decoupling-related revenue approved for recovery through volumetric rates is accumulated in deferred revenue accounts.

Operationally, this compliance verification was carried out in two steps:

- First, we traced calculations to insure conformance with Schedule 75(A, B, C, D, E) and Schedule 175(A, B, C, D, E). In carrying out this analysis, we checked to see that the reported calculations matched the methodological specifications in each Schedule. Also, we checked for 2015, 2016 and 2017 the component Excel spreadsheets introduced as Avista Exhibits for the annual filings for Tariff WN U-28 Electric Service for Electric Decoupling Rate Adjustment; and for Tariff WN U-29 Natural Gas Service for Natural Gas Decoupling Rate Adjustment as filed on August 31, 2016, August 31, 2017 and on August 17, 2018.
- Second, we have included the opinions of the independent auditor for 2015, 2016 and 2017 to indicate the validity of the financial data upon which the calculations depend.

The overall result in this section of the analysis is that we find the deferrals and rates to have been calculated by the Company in accordance with the Commission order and the Amended Petition, as determined by methodological specification in Schedule 75 and Schedule 175.

Section 2. Billing Impacts and Recovery of Cost of Service Analysis

There are two primary evaluation objectives associated with Task 2:

- Determine if there were any differences in decoupling tracker adjustments between rate classes.
- Determine if allowed revenues are recovering the cost of service for group one (residential) and group two (non-residential subject to decoupling)[25] and customers not subject to decoupling.

Each objective is addressed in a separate section. Both sections use the customer classes (rate categories) customarily used by Avista for cost of service analysis and for decoupling filings. These customer classes are listed in the table below for electric and natural gas customers.

Table 2-1. Electric and Natural Gas Rate Groups and Customer Classes (Rate Categories)

Electric Service					Natural Gas Service				
Rate Group	**Customer Class Code**	**Customer Class**	**Rate Schedules**	**De-coupled**	**Rate Group**	**Customer Class Code**	**Customer Class**	**Rate Schedules**	**De-coupled**
Residential	E1	Residential	1, 2	Yes	Residential	G1	Residential	101, 102	Yes
Non-Residential	E2A	General Services	11, 12	Yes	Non-Residential	G2A	General Services	111	Yes
Non-Residential	E2B	Large General Services	21, 22	Yes	Non-Residential	G2B	Large General Services	121	Yes
Non-Residential	E2C	Pumping	30, 31, 32	Yes	Non-Residential	G2C	Interruptible	131	Yes (a)
Non-Decoupled	E3A	Extra Large General Services	25	No	Non-Decoupled	G3A	Excluded Schedules1	112, 122, 132	No
Non- Decoupled	E3B	Street & Area Lighting	41 - 48	No	Non-Decoupled	G3B	Excluded Schedules 2	146, 148	No
(a) No customer history for natural gas Rate Schedule 131 (Interruptible) over the years requested (2012-2017)									

[25] For customers subject to decoupling, the mechanism captures all fixed costs allocated to the volumetric portion of customer bills. Avista states in response to Data Request 090 that "…on a customer basis there are no costs which are not captured in the mechanism."

For reporting and referencing purposes, we have defined a Customer Class Code for each rate category. The Customer Class Code identifies the fuel in the first character, electric (E) or natural gas (G), decoupling rate group in the second and a subset of the rate group defined by one or more rate schedules in the third. Separately for electric and natural gas, and as explained in the section of the evaluation covering Task 1, the decoupling mechanism defines two groups of customers subject to the decoupling tracker adjustment, residential (Rate Group 1) and non-residential (Rate Group 2). We also define Rate Group 3, non-residential customers not subject to the decoupling tariff. The aggregation level hierarchy listed from highest level of aggregation to the lowest is as follows:

1. Rate Group
2. Customer Class (Rate Category)
3. Rate Schedule

For example, Customer Class Code E1 is electric decoupling Rate Group 1, residential, and includes rate schedules 1 and 2. A third character is not necessary since Rate Group 1 only includes residential rate schedules. Rate Group 2 is non-residential customers subject to the decoupling adjustment tariff. There are three customer classes (collection of rate schedules) included in Rate Group 2 for both electric and natural gas service. Rate Group 3 is used to identify customers not subject to the decoupling tariff adjustment. Electric and natural gas each have two customer classes that belong to Rate Group 3.

Summary of Decoupling Mechanics and Results

Before examining the impact of decoupling by rate class it is useful to take a high-level look at the mechanics of the decoupling mechanism, actual deferrals, requested recovery amounts and decoupling rates. Avista's decoupling mechanism allows for the recovery of the difference between actual revenue and allowed revenue.[26] This difference is referred to as the decoupling deferral balance and is tracked for the two electric and two natural gas customer groups subject to decoupling; residential and non-residential.

Beginning in 2015, monthly deferrals are accumulated over a calendar year and used with other determinants to calculate the decoupling rate required to collect or refund the under or over collected revenue. Decoupling rates become effective in Schedule 75 (electric) and Schedule 175 (natural gas) November 1 of the year following the year in which deferral balances were calculated. The timing of deferral balance accumulation and decoupling rate adjustments is shown in Figure 2-1.

[26] The details of Avista's decoupling mechanism are included in Final Order ("Order 5") for Docket Numbers UE-140188 and UG-140189.

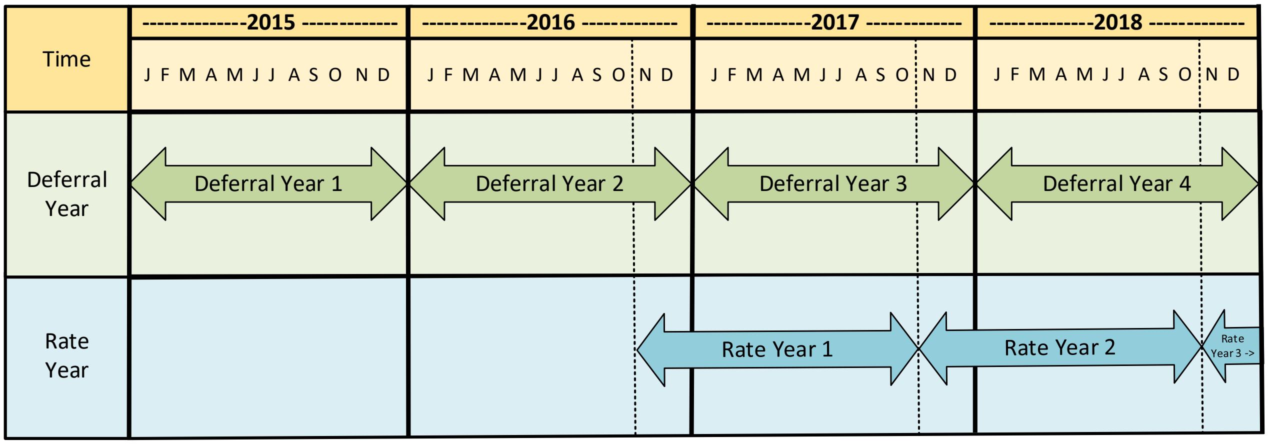


Figure 2-1. Timing of Deferral Balance Accumulation and Decoupling Rate

The first deferral year resulted in a deferral balance at the end of 2015 that was used, along with other determinants, to calculate the decoupling rate in effect during the first rate year (November 1, 2016 through October 31, 2017). The same process is followed in the second deferral year and rate year. Any deferral balance carried over from the first rate year due to the application of the 3% cap is included in the calculations of decoupling rates in effect during the second rate year (November 2017 through October 2018). Details of these calculations are shown in Table 2-2 for the first three years of operation of the decoupling mechanism.

Table 2-2. Summary of Deferral Balances and Decoupling Recovery Rates

----------------------------- Electric -----------------------------							
		Residential Group			**Non-Residential Group**		
	Notes	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**
Deferred Revenue ($)		7,167,748	10,288,205	-2,092,790	-2,373,472	1,967,777	1,735,911
Requested Recovery ($)	A	7,360,678	10,913,950	-2,765,635	-3,081,249	864,012	1,170,966
Customer Surcharge (Rebate) Revenue ($)		6,485,021	10,913,950	-2,765,635	-3,081,249	864,012	1,170,966
Carryover Deferred Revenue ($)		875,657	0	0	0	0	0
Decoupling Rate (Schedule 75) ($/kWh)	B	0.00263	0.00445	-0.00116	-0.00143	0.00040	0.00054
Incremental Revenue (Percent)		3.00%	2.00%	-5.78%	-1.40%	0.40%	0.14%
Limited by 3% Cap?		Yes	No	No	No	No	No
---------------------------- Natural Gas ----------------------------							
		Residential Group			**Non-Residential Group**		
	Notes	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**
Deferred Revenue ($)		5,317,198	7,152,977	-1,972,082	1,736,736	2,002,654	840,286
Requested Recovery ($)	A	5,750,096	7,652,369	-3,441,586	1,879,152	2,212,881	407,719
Customer Surcharge (Rebate) Revenue ($)		3,488,984	6,951,431	-3,441,586	1,108,839	2,212,881	407,719
Carryover Deferred Revenue ($)		2,261,112	700,938	0	770,313	0	0
Decoupling Rate (Schedule 175) ($/therm)	B	0.02927	0.05580	-0.02720	0.02108	0.03904	0.00691
Incremental Revenue (Percent)		3.00%	3.00%	-10.08%	3.00%	2.95%	-6.13%
Limited by 3% Cap?		Yes	Yes	No	Yes	No	No

A: Requested recovery is equal to deferred revenue after adjusting for shared excess earnings (if applicable), deferral balance carryover from prior year (if any), interest, and revenue related expenses.

B: Decoupling rates Schedule 75 (electric) and Schedule 175 (natural gas) take effect on November 1st of the following year. For example, rates shown in the 2016 column have an effective date of November 1, 2017

Years shown in Table 2-2 correspond to the deferral years and rate years shown in Figure 2-1. For example, the 2015 column refers to calculations made from data for deferral year one (2015) and the resulting deferral rates in effect for rate year one (November 1, 2016 through October 31, 2017). As a specific example, consider the workings of the decoupling mechanism as shown for the natural gas residential rate group in 2016. Cumulative deferral balances during the year amounted to $7.153 million. This amount along with adjustments, including the carryover of $2.261 million from 2015 requested recovery not amortized into rate year one due to the 3% cap, resulted in a requested recovery of $7.652 million. For the second consecutive year the 3% cap took effect, limiting the customer surcharge revenue expected from the new decoupling rate (effective November 1, 2017) to $6.951 million and resulting in carryover deferred revenue of $0.701 million.

An important characteristic of the Avista decoupling mechanism that applies to all rate groups and fuels is evident in the residential natural gas example. Because the 3% test is applied using current rates, including the current decoupling rate, the new decoupling rate will adjust higher and be capable of amortizing higher levels of requested recovery.[27] At some point, even if weather or other conditions that caused initially high deferral carryovers persist, the decoupling rate will eventually adjust to a level that recovers 100 percent of requested recovery and carryover deferral balances will fall to zero. This greatly reduces the possibility of snow-balling deferral balances even in the face of persistently warm winters over consecutive heating seasons. This point is well illustrated for residential natural gas customers. Carryover deferred revenue fell from $2.261 million for the 2015 deferral year to $0.701 million in 2016 even though deferred revenue and the requested recovery was nearly two million dollars higher for the 2016 deferral year. Heating degree days were 15% less than normal (warmer winter weather) in 2015 and 14% less than normal in 2016.

Factors Influencing Use per Customer

Avista relies on volumetric charges to recover a portion of fixed costs for all rate groups and fuels. This causes use per customer to be an important factor in determining deferral balances and decoupling rates through the decoupling mechanism. More specifically, changes in use per customer from levels used in the test year to set decoupled revenue will lead to positive or negative deferral balances depending on the direction of change, all other things equal. Higher use per customer will cause negative deferrals and lower use per customer will result in higher deferrals, again all other things equal.

Two important factors causing use per customer to vary from test year are actual weather deviations from normal weather and acquired energy efficiency savings through Avista programs. There are other factors of course but these two are either known in the case of energy efficiency or readily measurable in the case of weather.

[27] This is a special feature of the Avista decoupling mechanism that makes the mechanism flexible.

Electric

The table below shows calculations for estimating these impacts on electric use per customer.

Table 2-3. Electric Use per Customer Variance from Test Year

	2015			2016			2017		
	Usage (MWh)	Customers	Use per Customer (kWh)	Usage (MWh)	Customers	Use per Customer (kWh)	Usage (MWh)	Customers	Use per Customer (kWh)
	-------------------- Residential --------------------								
Test Year	2,437,508	207,850	11,727	2,378,478	205,172	11,593	2,378,478	205,172	11,593
Actual	2,323,300	207,371	11,204	2,288,227	209,864	10,903	2,492,293	212,495	11,729
Change from Test Year	(114,208)	(479)	(524)	(90,251)	4,692	(689)	113,815	7,323	136
Percent Change	-4.7%	-0.2%	-4.5%	-3.8%	2.3%	-5.9%	4.8%	3.6%	1.2%
Change from Test Year Due to:									
Weather	(33,120)		(160)	(73,659)		(351)	113,472		534
Cumulative Energy Efficiency	0		0	(33,272)		(159)	(61,500)		(289)
	-------------------- Non-Residential --------------------								
Test Year	2,150,843	35,277	60,970	2,144,857	34,823	61,593	2,144,857	34,823	61,593
Actual	2,179,747	35,265	61,810	2,158,998	35,617	60,618	2,184,830	35,994	60,700
Change from Test Year	28,904	(12)	840	14,142	794	(975)	39,974	1,171	(893)
Percent Change	1.3%	0.0%	1.4%	0.7%	2.3%	-1.6%	1.9%	3.4%	-1.5%
Change from Test Year Due to:									
Weather	10,361		294	(7,200)		(202)	28,851		802
Cumulative Energy Efficiency	-		0	(41,935)		(1,177)	(81,076)		(2,252)

The test year used for 2015 deferral calculations was a projection of 2015. The test years for 2016 and 2017 both used a 12-month period ending September 2014. Actual usage, customers and use per customer compared to the test year are straightforward calculations. Changes due to weather are also straightforward calculations, the results of which are also shown in Table 2-3 in terms of total and use per customer impacts. Avista provided the weather impacts and supporting monthly details by rate schedule showing the deviation in heating and cooling degree days from normal and the corresponding model coefficient on each weather term. Energy efficiency impacts are calculated as cumulative savings from Avista programs since the test year.

One way to quickly visualize the results of the calculations shown in Table 2-3 is a plot of each factor's influence on the percent change in use per customer from the test year. Figure 2-8 presents this information for the electric residential rate group.

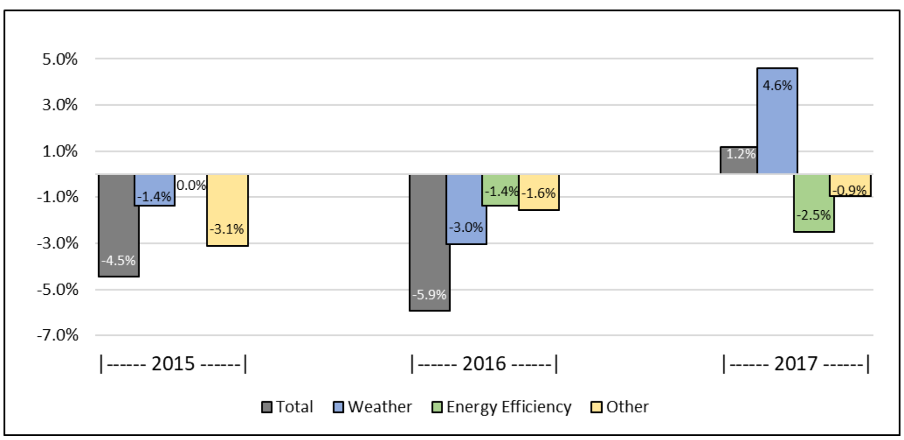


Figure 2-2. Percentage Change in Use per Customer, Electric Residential

Considering 2017 results, use per customer was 1.2% higher than test year assumptions. Weather impacts alone are estimated to have pushed electric residential use per customer 4.6% higher. The 2017 weather impact was largely offset by a 2.5% drop in use per customer due to Avista's energy efficiency achievements. The "Other" category is simply the difference between the total and the readily quantifiable factors of weather and energy efficiency. Other unidentified factors have pushed use per customer lower and have been lessening in influence over time.

For electric residential customers weather impacts on use per customer can be large and work in either direction. It is also true that energy efficiency impacts always push use per customer lower and that downward influence becomes more pronounced the further in time an evaluation year is from the test year. Cumulative energy efficiency savings will reset with a new rate case and test year.

Figure 2-3 shows a plot of total and each factor's influence on the percent change in use per customer from the test year for the electric non-residential rate group.

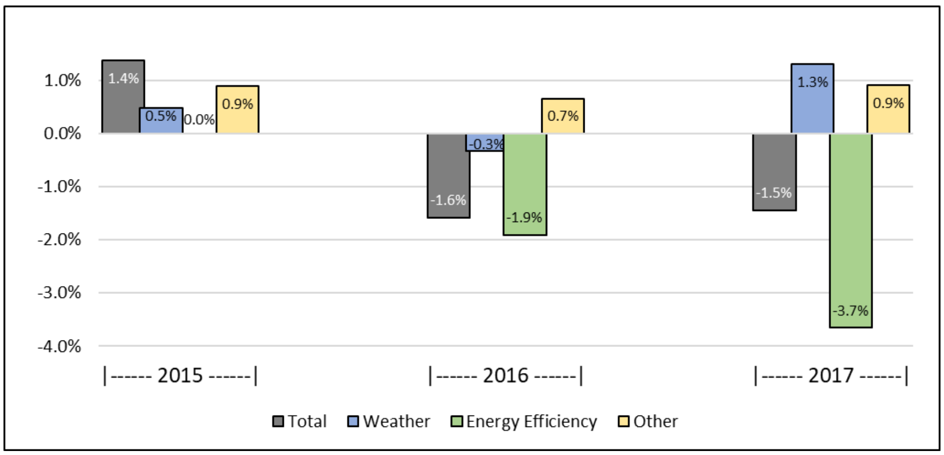


Figure 2-3. Percentage Change in Use per Customer, Electric Non-Residential

Avista's energy efficiency achievements have been the primary factor influencing changing use per customer in the electric non-residential group. From having no influence in 2015 because they were implicitly included in test year assumptions, energy efficiency impacts more than offset weather and other factors in 2017 causing an overall drop in use per customer of 1.5%. Weather appears to be far less influential in electric non-residential customer usage than it is for the electric residential group. Other unidentified factors have pushed use per customer higher at a small but consistent percentage over time.

Natural Gas

The same analysis of the factors impacting changes in electric use per customer were also completed for the natural gas rate groups. Results of the analysis are shown in Table 2-4.

Table 2-4. Natural Gas Use per Customer Variance from Test Year

	2015			2016			2017		
	Usage (MWh)	Customers	Use per Customer (kWh)	Usage (MWh)	Customers	Use per Customer (kWh)	Usage (MWh)	Customers	Use per Customer (kWh)
	-------------------- Residential --------------------								
Test Year	117,011,207	150,186	779	120,721,607	148,995	810	120,721,607	148,995	810
Actual	103,436,220	151,254	684	108,796,187	153,995	706	131,782,922	157,563	836
Change from Test Year	(13,574,987)	1,068	(95)	(11,925,420)	5,000	(104)	11,061,315	8,568	26
Percent Change	-11.6%	0.7%	-12.2%	-9.9%	3.4%	-12.8%	9.2%	5.8%	3.2%
Change from Test Year Due to:									
Weather	(15,318,639)		(101)	(10,650,431)		(69)	4,404,967		28
Cumulative Energy Efficiency	0		0	(360,660)		(2)	(931,120)		(6)
	-------------------- Non-Residential --------------------								
Test Year	51,764,097	2,548	20,316	52,606,812	2,584	20,358	52,606,812	2,584	20,358
Actual	45,886,568	2,651	17,309	48,208,894	2,770	17,404	55,684,308	2,918	19,083
Change from Test Year	(5,877,529)	103	(3,006)	(4,397,918)	186	(2,954)	3,077,496	334	(1,275)
Percent Change	-11.4%	4.0%	-14.8%	-8.4%	7.2%	-14.5%	5.8%	12.9%	-6.3%
Change from Test Year Due to:									
Weather	(5,357,641)		(2,021)	(3,631,036)		(1,311)	1,407,324		482
Cumulative Energy Efficiency	-		0	(687,328)		(248)	(903,662)		(310)

As with electric, the natural gas decoupling mechanism used a projection of 2015 as the 2015 test year. The natural gas test year for 2016 and 2017 both used a 12-month period ending September 2014. Again, these definitions of test periods are consistent with the electric decoupling mechanism. The calculations shown in Table 2-6 are also consistent with the approach described for electric and presented in Table 2-3.

Results of the analysis of changes in natural gas use per customer are visually represented in Figure 2-4 for the natural gas residential group.

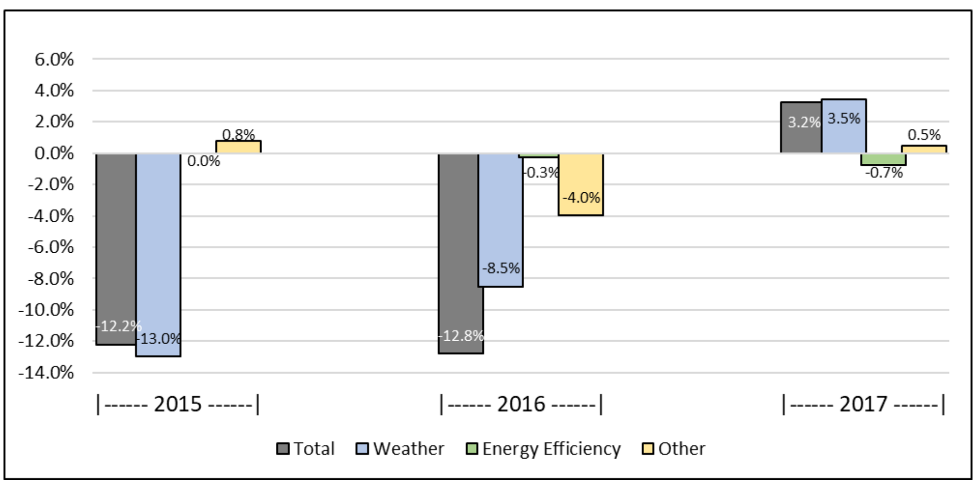


Figure 2-4. Percentage Change in Use per Customer, Natural Gas Residential

Weather is clearly the dominant factor in understanding changes in residential therm use per customer from the test year. The total change in use per customer tracks the warmer than normal heating seasons in calendar years 2015 and 2016 and slightly colder than normal heating season in calendar year 2017. Energy efficiency impacts on use per customer are a small factor in understanding overall change from the test year. Natural gas prices have been persistently low, squeezing the cost effectiveness of natural gas efficiency programs. Other unidentified factors were small in 2015 and 2017 but relatively high in 2016. One possible explanation is that the 2016 weather adjustment was understated by the weather normalization model.

Figure 2-5 shows a plot of total and each factor's influence on the percent change in use per customer from test year assumptions for the natural gas non-residential rate group.

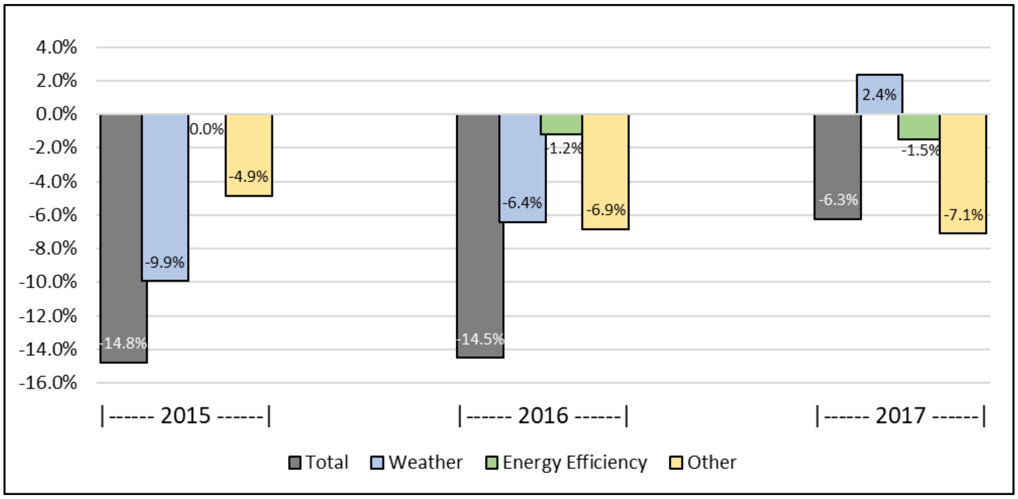


Figure 2-5. Percentage Change in Use per Customer, Natural Gas Non-Residential

Except for weather in 2017, all factors in each year have contributed toward lower use per customer than test year assumptions. Unlike any of the other electric or natural gas rate groups, other factors are an important influence on use per customer for the natural gas non-residential group in each of the years examined. Other factors are by definition unquantified but could include increased efficiency outside of Avista's energy efficiency programs, lower use of natural gas due to fuel substitution (e.g. increased use of biomass in cogeneration) and cutbacks in customer facility operations. Weather is also influential although less so than for natural gas residential customers. Energy efficiency impacts on use per customer are a small factor in understanding overall change from the test year. Again, this could be due in part to persistently low natural gas prices putting pressure on the cost effectiveness of natural gas efficiency programs.

Avista's electric and natural gas energy efficiency programs are discussed in detail in Section 3 and Section 6 of this report. An examination of actual weather experienced over the three evaluation years is presented next.

Weather Compared to Normal

The impact of weather depends on the level of weather sensitive energy usage and the difference between actual and normal weather.[28] Weather that causes greater usage results in over collection of allowed revenue (negative deferral balances) and vice versa. Residential is the most weather sensitive customer group and natural gas customers are typically more weather sensitive than electric customers because space conditioning makes up a greater percentage of natural gas usage than electric. Given these relationships we would expect the residential natural gas customer group to have the largest weather-related impacts on decoupling deferral balances and rates.

Heating degree days are useful for describing atmospheric temperatures in units related to the need for space heating. Figure 2-6 shows the difference between actual and normal heating degree days (HDD) from January 2015 through December 2017. A negative value means warmer than normal weather (i.e., less than normal need for space heating).

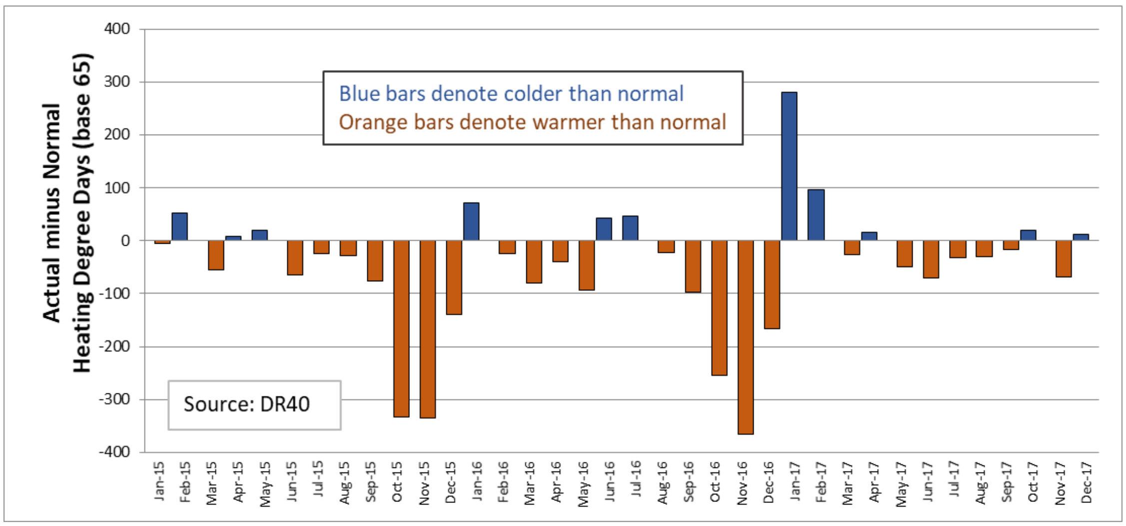


Figure 2-6. Monthly Heating Degree Days (difference from normal)

Actual weather was predominately warmer than normal in 2015 and 2016. In 2017 actual HDDs were much closer to but higher than normal, indicating a return to slightly greater but near normal space heating loads. As shown earlier in this section, this weather pattern has the expected impact on use per customer for natural gas residential and non-residential groups. Space heating is the predominant end-use for the natural gas residential group and a major end-use in the natural gas non-residential group.

For both of Avista's electric customer rate groups, the need for space cooling is also an important determination of use per customer. Cooling degree days are useful for describing atmospheric temperatures in units related to the need for space cooling. Figure 2-7 shows the difference between actual and normal cooling degree days (CDD) from January 2015 through

[28] For this analysis, normal weather is defined as a thirty-year moving average.

December 2017. A negative value means cooler than normal weather (i.e., less than normal need for space cooling).

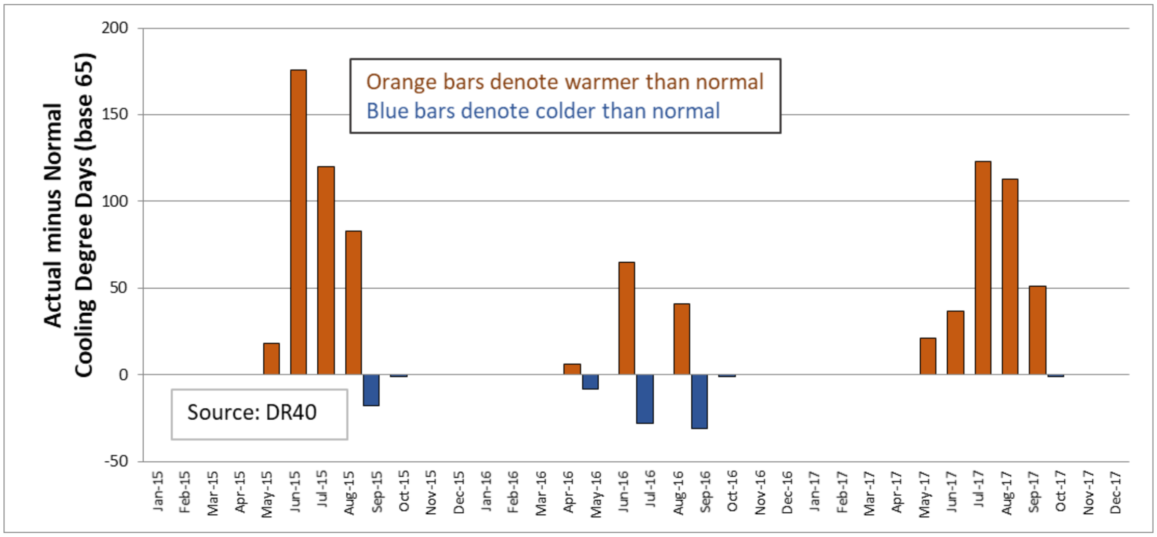


Figure 2-7. Monthly Cooling Degree Days (difference from normal)

As shown by the monthly bars, significant warmer than normal weather was experienced in the summer months of 2015 and 2017 and somewhat warmer than normal in the summer of 2016. This would have led to greater than normal levels of electric loads for space cooling in both residential and non-residential rate groups in all deferral years, especially 2015 and 2017. The increased usage for space cooling would put downward pressure on deferral balances, all else held constant. This is especially true for the non-residential group where space cooling is likely to be a larger percentage of total usage than the residential rate group.

Monthly heating and cooling degree data are summarized for each of the three calendar years in Table 2-5.

Table 2-5. Comparison of Actual and Normal Annual Heating Degree Days

	Heating Degree Days			**Cooling Degree Days**		
	2015	**2016**	**2017**	**2015**	**2016**	**2017**
Actual	5,611	5,610	6,725	828	494	794
Normal	6,629	6,547	6,513	477	478	490
Percent Difference	-15.4%	-14.3%	3.3%	73.6%	3.3%	62.0%
Source: DR 40 and DR 76						

Weather can be an important factor, along with energy efficiency achievements, contributing to actual use per customer variances from projected levels. It stands to reason that decoupling deferral balances are related to weather patterns. Holding everything else constant and considering just the variances from normal degree days shown in Table 2-5 it would be reasonable to expect deferral balances for both natural gas rate groups to be positive in 2015 and 2016 and near zero or slightly negative in 2017. This is in fact the pattern of deferral balances observed in both groups. For electric rate groups the presence of cooling loads makes it more difficult to explain deferral balances solely on the weather when heating and cooling differences from normal cause use per customer to move in opposite directions. This is the case in 2015 and 2016 when less than normal HDDs put downward pressure on use per customer and greater than normal CDDs put upward pressure on use per customer.

Earlier in this section the balance of these offsetting weather impacts was quantified and described along with energy efficiency and other factors impacting use per customer. Especially for electric rate groups weather is only a part of the story for understanding usage and energy efficiency achievements are an important factor in determining changes in use per customer. Avista's energy efficiency achievements are described in detail in Section 3 and Section 6 of this evaluation.

Task 2 Part 1: Impact of Decoupling Tracker Adjustment by Customer Class

The objective for the first part of this task, as stated in the request for proposal, is shown below:

> *"An assessment of the impacts of the Decoupling tariff tracker adjustments, calculated in relation to energy sales (kWh/therms), as a percent of monthly bills, and in total dollars for each rate category customarily used for purposes of Avista's cost of service analyses."*

Relating to this objective is the following evaluation question, also taken from the RFP:

> *"Were there any differences in Decoupling tracker adjustments between the rate classes?"*

We begin our analysis and reporting for this task with electric customer classes followed by natural gas customer classes.

Electric

Six years of historical customer counts by customer class are shown in Table 2-6. Although, Rate Group 3 is not subject to decoupling, Customer Classes E3A and E3B are included for completeness and perspective.

Table 2-6. Annual Electric Customer Counts by Customer Class

Year	E1: Residential	E2A: General Services	E2B: Large General Services	E2C: Pumping	E3A: Excluded Extra Large General Services	E3B: Excluded Street & Area Lighting	Total
2012	202,541	28,868	2,440	2,416	22	357	236,644
2013	203,883	29,622	2,050	2,427	21	375	238,378
2014	205,621	30,570	2,011	2,435	21	381	241,039
2015	209,419	31,089	2,027	2,445	23	400	245,403
2016	209,864	31,286	1,903	2,433	21	409	245,916
2017	212,495	31,666	1,896	2,432	22	413	248,924

Avista serves approximately one quarter of a million electric customers in the state of Washington. All but about 400 of these customers are subject to the decoupling tracker adjustment. Customer growth has varied year to year consistent with economic conditions and construction activity, averaging about one percent annually for residential and slightly higher for non-residential customers. As discussed in the previous section, although the decoupling mechanism was effective January 1, 2015, the decoupling tracker adjustment did not show up on customer bills until late in 2016. Customer growth in 2017 was near the average of the 2012-2017 period, 1.3% for residential (slightly above the average of 1.0%) and 1.0% for non-residential (slightly below the average of 1.3%).

Annual revenues by electric customer class over the 2012 through 2017 period are shown in Table 2-7. For perspective and completeness Rate Group 3 customer classes are shown in the table even though they are not subject to the decoupling mechanism.

Table 2-7. Annual Electric Revenue by Customer Class

Year	E1: Residential	E2A: General Services	E2B: Large General Services	E2C: Pumping	E3A: Excluded Extra Large General Services	E3B: Excluded Street & Area Lighting	Total
	(thousands of dollars)						
2012	193,907	59,984	129,863	10,068	58,697	6,772	459,290
2013	205,149	67,922	126,981	10,431	61,511	6,694	478,687
2014	208,603	70,884	128,958	11,576	64,355	6,932	491,308
2015	208,022	73,727	133,362	12,516	70,931	7,201	505,758
2016	207,405	74,978	129,316	11,265	66,571	7,089	496,624
2017	237,119	78,186	130,454	11,396	68,445	6,776	532,376

Avista billed Washington electric customers $532 million in 2017, up over 7% from 2016 due primarily to the effect on residential customers of a return to colder than normal weather. Like most electric and natural gas utilities, Avista's billed revenue varies significantly with the weather. Eighty six percent (86%) of revenue in 2017 was collected from Rate Groups 1 and 2, and subject to the decoupling tariff tracker. Total revenue and Schedule 75 revenue are shown in Table 2-8 for these four customer classes. Schedule 75 revenue is the revenue collected through the decoupling adjustment mechanism.

Table 2-8. Annual Decoupling Tariff Revenue by Electric Customer Class

	2016			2017		
Electric Customer Class	Revenue	Schedule 75 Revenue	Percent of Bill	Revenue	Schedule 75 Revenue	Percent of Bill
E1: Residential	207,405,033	821,187	0.4%	237,118,808	7,168,350	3.0%
E2A: General Services	74,978,073	-106,490	-0.1%	78,185,893	-777,980	-1.0%
E2B: Lg Gen Services	129,315,832	-236,728	-0.2%	130,454,356	-1,723,065	-1.3%
E2C: Pumping	11,265,056	-6,223	-0.1%	11,396,073	-188,410	-1.7%

In 2016 Schedule 75 revenue amounted to a small percent of the overall billed revenue for a customer class. Schedule 75 adjustment to rates first took effect on November 1, 2016, muting the annual 2016 impact. The decoupling adjustment amounted to 0.4% of 2016 residential bills. The customer classes in the non-residential rate group (Group 2) had slightly lower bills in 2016 due to Schedule 75. The difference in the direction of Schedule 75 impact on billed revenue between rate groups is due to deferral balance differences shown in the previous section.

Schedule 75 revenue is significantly higher in 2017, the first full calendar year with Schedule 75 in rates. Although still small in percentage of revenue terms, Schedule 75 accounted for 3% of billed residential revenue in 2017. The billed revenue impact was negative for Group 2 customers, ranging from -1.0% of revenue for General Services customers and -1.7% for Pumping customers.

The pattern of monthly impacts, discussed next, provides insight on what to expect for 2018. Summarizing impacts annually is useful at a high level but a monthly view is necessary to examine the pattern of usage and impact on bills from the decoupling mechanism. Monthly details are shown by electric customer class for 2016 and 2017 in Table 2-9 and Table 2-10, respectively. These tables show total usage, revenue, meters (customers), average usage, average revenue, and Schedule 75 revenue (total, average, and as a percent of revenue) for customer classes subject to the decoupling mechanism.

Monthly revenue impacts follow the pattern of volumetric sales. As a result, customer classes with high seasonality also show high seasonality in the average customer's monthly Schedule 75 charge. Due to weather induced seasonality in monthly usage, the surcharge paid per customer varies significantly by month for the Residential Rate Group, ranging from a low of $0.86 per customer in November 2016 as Schedule 75 began to be phased into customer bills, to a high of $5.10 per customer in December 2017.

A review of the monthly data in Table 2-9 and Table 2-10 shows that the percentage impact of Schedule 75 on total revenue tends to be relatively constant from month-to month. The months of November and December can be exceptions and show significant differences in Schedule 75 revenue percentage from preceding months. This is due to the November 1 effective date of new Schedule 75 rate adjustments. For example, the Schedule 75 percent for the General Services class went from -1.1% in October 2017 to 0.3% in December 2017 as the new Schedule 75 rate effective November 1, 2017 became fully reflected in customer bills.[29]

[29] Although the effective date of revised Schedule 75 rates was November 1, customer bills in November reflect usage that is partially billed at the old Schedule 75 rate and part billed at the new Schedule 75 rate. The portion billed under the old and new rates is determined by a simple prorating of usage based on the number of calendar days in the billing period before November 1 and the number of days on or after November 1.

Table 2-9. 2016 Electric Monthly Billing Data

	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	TOTAL
E1: RESIDENTIAL													
Total Usage (kWh)	281,027,480	230,506,821	198,363,507	175,201,661	148,495,652	154,090,137	163,425,633	176,921,758	176,555,296	148,062,106	171,637,794	244,773,659	2,269,061,504
Total Revenue ($)	25,630,827	20,881,166	17,916,278	15,817,614	13,485,159	13,978,673	14,848,991	16,154,290	16,160,405	13,635,478	15,857,718	23,038,434	207,405,033
Number of Meters	208,217	210,418	209,750	209,405	209,004	208,965	209,204	209,512	210,314	210,674	211,346	211,562	209,864
Avg Usage (kWh)	1,350	1,095	946	837	710	737	781	844	839	703	812	1,157	10,812
Average Revenue ($)	123	99	85	76	65	67	71	77	77	65	75	109	988
Total Schedule 75 Revenue ($)	0	0	0	0	0	0	0	0	0	8	181,297	639,882	821,187
Avg Schedule 75 Revenue ($)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.86	3.02	3.91
Percent of Avg Bill	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	2.8%	0.4%
E2A: GENERAL SERVICES													
Total Usage (kWh)	62,103,053	55,492,050	51,335,713	47,127,306	45,475,268	46,917,495	48,733,807	51,765,642	52,690,785	45,883,770	46,983,800	57,305,285	611,813,974
Total Revenue ($)	7,354,645	6,706,943	6,270,124	5,841,911	5,654,397	5,797,372	5,990,673	6,343,772	6,470,890	5,783,943	5,864,035	6,899,367	74,978,073
Number of Meters	30,942	31,232	31,227	31,188	31,303	31,240	31,256	31,343	31,305	31,485	31,460	31,455	31,286
Avg Usage (kWh)	2,007	1,777	1,644	1,511	1,453	1,502	1,559	1,652	1,683	1,457	1,493	1,822	19,555
Average Revenue ($)	238	215	201	187	181	186	192	202	207	184	186	219	2,397
Total Schedule 75 Revenue ($)	0	0	0	0	0	0	0	0	0	(1)	(26,204)	(80,285)	(106,490)
Avg Schedule 75 Revenue ($)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.83)	(2.55)	(3.40)
Percent of Avg Bill	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.4%	-1.2%	-0.1%
E2B: LARGE GENERAL SERVICES													
Total Usage (kWh)	125,186,862	112,643,414	107,231,528	112,981,690	112,626,772	118,295,108	119,288,439	119,517,243	125,067,964	111,371,375	108,423,915	125,109,526	1,397,743,836
Total Revenue ($)	11,313,044	10,409,116	9,923,650	10,486,872	10,446,316	10,950,783	11,065,076	11,155,549	11,567,678	10,540,070	10,148,931	11,308,745	129,315,832
Number of Meters	1,951	1,928	1,895	1,910	1,897	1,901	1,895	1,887	1,899	1,889	1,889	1,895	1,903
Avg Usage (kWh)	64,165	58,425	56,587	59,153	59,371	62,228	62,949	63,337	65,860	58,958	57,398	66,021	734,495
Average Revenue ($)	5,799	5,399	5,237	5,491	5,507	5,761	5,839	5,912	6,091	5,580	5,373	5,968	67,954
Total Schedule 75 Revenue ($)	0	0	0	0	0	0	0	0	0	0	(63,440)	(173,288)	(236,728)
Avg Schedule 75 Revenue ($)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(33.58)	(91.45)	(124.40)
Percent of Avg Bill	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.6%	-1.5%	-0.2%
E2C: PUMPING													
Total Usage (kWh)	3,962,569	3,835,415	3,817,404	5,668,911	11,827,237	17,473,357	21,240,193	24,373,405	21,721,978	12,100,052	3,753,578	3,803,632	133,577,730
Total Revenue ($)	377,549	367,333	365,519	511,177	996,213	1,422,553	1,713,307	1,955,460	1,768,189	1,032,957	384,968	369,832	11,265,056
Number of Meters	2,438	2,412	2,449	2,399	2,458	2,441	2,368	2,464	2,465	2,454	2,413	2,432	2,433
Avg Usage (kWh)	1,625	1,590	1,559	2,363	4,812	7,158	8,970	9,892	8,812	4,931	1,556	1,564	54,908
Average Revenue ($)	155	152	149	213	405	583	724	794	717	421	160	152	4,631
Total Schedule 75 Revenue ($)	0	0	0	0	0	0	0	0	0	0	(1,410)	(4,813)	(6,223)
Avg Schedule 75 Revenue ($)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.58)	(1.98)	(2.56)
Percent of Avg Bill	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.4%	-1.3%	-0.1%

Table 2-10. 2017 Electric Monthly Billing Data

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	TOTAL
E1: RESIDENTIAL													
Total Usage (kWh)	328,204,493	275,264,984	227,842,125	191,579,775	164,336,749	154,995,685	174,494,045	202,126,296	185,654,057	158,083,535	193,502,303	246,386,721	2,502,470,768
Total Revenue ($)	31,350,022	26,114,270	21,484,843	17,986,535	15,471,354	14,643,313	16,410,432	19,007,693	17,533,688	14,994,830	18,396,962	23,724,868	237,118,808
Number of Meters	212,134	212,059	212,618	212,018	211,258	211,830	211,439	212,411	212,339	213,798	213,856	214,177	212,495
Avg Usage (kWh)	1,547	1,298	1,072	904	778	732	825	952	874	739	905	1,150	11,777
Average Revenue ($)	148	123	101	85	73	69	78	89	83	70	86	111	1,116
Total Schedule 75 Revenue ($)	863,088	723,914	599,203	503,828	432,218	407,643	458,821	531,604	488,277	415,771	650,764	1,093,219	7,168,350
Avg Schedule 75 Revenue ($)	4.07	3.41	2.82	2.38	2.05	1.92	2.17	2.50	2.30	1.94	3.04	5.10	33.73
Percent of Avg Bill	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	3.5%	4.6%	3.0%
E2A: GENERAL SERVICES													
Total Usage (kWh)	69,639,379	62,715,188	55,420,473	49,931,059	45,551,600	46,970,717	49,125,818	55,050,314	52,837,851	46,342,805	49,944,410	57,177,776	640,707,390
Total Revenue ($)	8,132,069	7,444,497	6,719,641	6,136,001	5,684,455	5,829,780	6,027,863	6,651,048	6,468,476	5,821,251	6,229,478	7,041,334	78,185,893
Number of Meters	31,582	31,490	31,659	31,538	31,392	31,756	31,572	31,796	31,755	31,890	31,616	31,947	31,666
Avg Usage (kWh)	2,205	1,992	1,751	1,583	1,451	1,479	1,556	1,731	1,664	1,453	1,580	1,790	20,233
Average Revenue ($)	257	236	212	195	181	184	191	209	204	183	197	220	2,469
Total Schedule 75 Revenue ($)	(99,582)	(89,733)	(79,252)	(71,396)	(65,129)	(67,163)	(70,245)	(78,717)	(75,553)	(66,261)	(35,541)	20,593	(777,980)
Avg Schedule 75 Revenue ($)	(3.15)	(2.85)	(2.50)	(2.26)	(2.07)	(2.11)	(2.22)	(2.48)	(2.38)	(2.08)	(1.12)	0.64	(24.57)
Percent of Avg Bill	-1.2%	-1.2%	-1.2%	-1.2%	-1.1%	-1.2%	-1.2%	-1.2%	-1.2%	-1.1%	-0.6%	0.3%	-1.0%
E2B: LARGE GENERAL SERVICES													
Total Usage (kWh)	131,962,124	121,904,042	113,711,113	110,407,518	108,649,337	115,767,544	118,417,390	124,991,961	123,316,003	108,948,024	115,016,232	123,409,034	1,416,500,321
Total Revenue ($)	11,777,863	11,064,040	10,434,852	10,172,816	10,085,530	10,721,135	10,969,641	11,451,523	11,364,341	10,253,727	10,700,620	11,458,269	130,454,356
Number of Meters	1,884	1,898	1,893	1,897	1,889	1,904	1,893	1,904	1,899	1,893	1,896	1,901	1,896
Avg Usage (kWh)	70,044	64,228	60,069	58,201	57,517	60,802	62,555	65,647	64,937	57,553	60,663	64,918	747,132
Average Revenue ($)	6,252	5,829	5,512	5,363	5,339	5,631	5,795	6,014	5,984	5,417	5,644	6,027	68,808
Total Schedule 75 Revenue ($)	(188,706)	(174,237)	(162,607)	(157,883)	(155,369)	(165,548)	(169,337)	(178,739)	(176,342)	(155,796)	(79,348)	40,845	(1,723,065)
Avg Schedule 75 Revenue ($)	(100.16)	(91.80)	(85.90)	(83.23)	(82.25)	(86.95)	(89.45)	(93.88)	(92.86)	(82.30)	(41.85)	21.49	(908.83)
Percent of Avg Bill	-1.6%	-1.6%	-1.6%	-1.6%	-1.5%	-1.5%	-1.5%	-1.6%	-1.6%	-1.5%	-0.7%	0.4%	-1.3%
E2C: PUMPING													
Total Usage (kWh)	4,114,424	4,433,880	4,576,516	4,451,164	7,314,108	14,910,662	23,854,142	30,594,405	23,144,049	11,688,998	4,880,546	3,366,624	137,329,517
Total Revenue ($)	389,284	417,478	426,104	416,359	637,403	1,223,511	1,882,387	2,382,676	1,841,934	978,615	466,727	333,597	11,396,073
Number of Meters	2,417	2,401	2,475	2,422	2,423	2,444	2,421	2,488	2,450	2,429	2,435	2,374	2,432
Avg Usage (kWh)	1,702	1,847	1,849	1,838	3,019	6,101	9,853	12,297	9,447	4,812	2,004	1,418	56,477
Average Revenue ($)	161	174	172	172	263	501	778	958	752	403	192	141	4,687
Total Schedule 75 Revenue ($)	(5,881)	(6,340)	(6,544)	(6,382)	(10,459)	(21,322)	(34,111)	(43,750)	(33,096)	(16,715)	(4,609)	799	(188,410)
Avg Schedule 75 Revenue ($)	(2.43)	(2.64)	(2.64)	(2.64)	(4.32)	(8.72)	(14.09)	(17.58)	(13.51)	(6.88)	(1.89)	0.34	(77.48)
Percent of Avg Bill	-1.5%	-1.5%	-1.5%	-1.5%	-1.6%	-1.7%	-1.8%	-1.8%	-1.8%	-1.7%	-1.0%	0.2%	-1.7%

To visualize and contrast the impacts on customer electric revenues between customer classes, the percentage of monthly electric revenues attributed to Schedule 75 from the time rates were first impacted by the decoupling mechanism through December 2017 is shown in Figure 2-8.

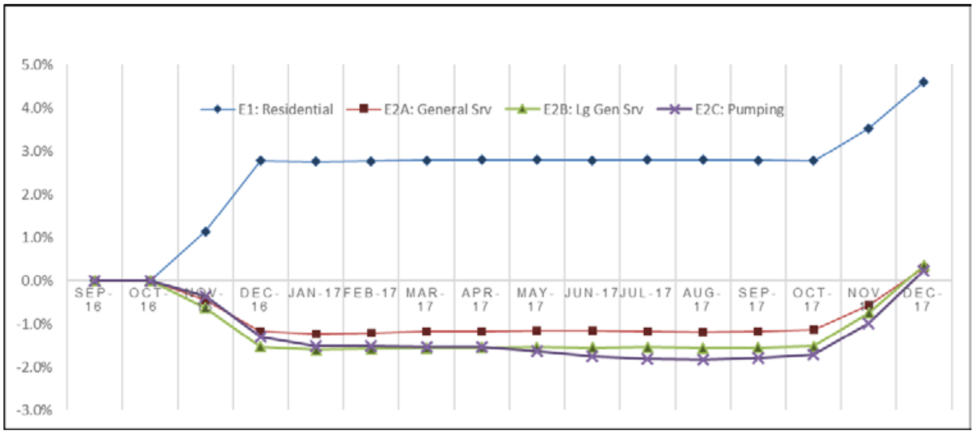


Figure 2-8. Schedule 75 as a Percent of Monthly Customer Class Revenues

Figure 2-8 shows monthly Schedule 75 revenue as a percentage of total revenue for each customer class subject to decoupling. The impact on revenue of the first decoupling tariff adjustment effective November 1, 2016 can be seen beginning with November 2016 billed revenue. Residential customers saw the partial impact of Schedule 75 in November 2016 and the full impact in December 2016 with Schedule 75 revenue accounting for 2.8% of revenue. Schedule 75 revenue as a percent of class revenue increased again with new rates effective November 1, 2017. In incremental percentage terms, the 2017 increase was smaller than the 2016 increase in Schedule 75 revenue. In December 2017 when the full impact of the second year decoupling adjustment is reflected in rates, Residential Schedule 75 revenues were 4.6% of total revenue, 1.8 percentage points higher than the first rate adjustment revenue impact. As indicated by the long straight line near 3% for the Residential group in Figure 2-8, Schedule 75 was limited by the 3% annual cap in the first rate year but not in the second year, resulting in the smaller incremental increase of about 2% in rate year two (from around 3% to 5%).

For Group 2 (non-residential) customer classes, Schedule 75 had the impact of lowering customer bills with the first rate year adjustment (effective November 1, 2016). On a monthly basis, the full impact of Schedule 75 as percentage of total revenue ranged from -1.1% to -1.8%, depending on the month and customer class. This effective rebate from decoupling was reversed with the second rate year (effective November 1, 2017), resulting in Schedule 75 as a percentage of revenues ranging from 0.2% to 0.4% in December 2017. The 3% rate cap did not impact electric Group 2 customer classes in either 2016 or 2017.

Natural Gas

Six years of historical customer counts by customer class are shown in Table 2-11. Although Rate Group 3 is not subject to decoupling, Customer Classes G3A and G3B are included for completeness and perspective.

Table 2-11. Annual Natural Gas Customer Counts by Customer Class

Year	G1: Residential	G2A: General Services	G2B: Large General Services	G3A: Excluded Schedules 1	G3B: Excluded Schedules 2	Total
2012	146,776	2,476	25	5	46	149,328
2013	147,880	2,498	26	4	49	150,457
2014	149,453	2,575	26	4	48	152,106
2015	152,182	2,648	26	4	43	154,903
2016	153,955	2,749	22	4	44	156,774
2017	157,563	2,896	22	4	45	160,530

Avista serves approximately 160,000 natural gas customers in the state of Washington. All but about 50 of these customers are subject to the decoupling tracker adjustment. Customer growth has varied year to year consistent with economic conditions and construction activity, averaging 1.4% annually for residential and 3.1% for non-residential customers. As discussed in the previous section, although the decoupling mechanism was effective January 1, 2015, the decoupling tracker adjustment did not show up on customer bills until late in 2016. Customer growth in 2017 was higher than experienced over the 2012-2017 period, 2.3% for residential and 5.3% for non-residential.

Annual revenues by customer class over the 2012 through 2017 period are shown in Table 2-12. For perspective and completeness Rate Group 3 customer classes are shown in the table even though they are not subject to the decoupling mechanism.

Table 2-12. Annual Natural Gas Revenue by Customer Class

Year	G1: Residential	G2A: General Services	G2B: Large General Services	G3A: Excluded Schedules 1	G3B: Excluded Schedules 2	Total
	(thousands of dollars)					
2012	103,264	32,161	3,176	1,546	3,297	143,444
2013	108,136	32,719	3,255	1,184	3,506	148,801
2014	114,968	36,439	3,520	1,060	3,597	159,584
2015	107,638	33,807	3,335	1,027	3,686	149,493
2016	102,989	31,098	2,441	928	4,121	141,577
2017	123,005	35,230	2,467	879	4,673	166,254

Avista billed Washington natural gas customers $166 million in 2017, up 17% from 2016 due primarily to a return to colder than normal weather and to a lesser extent rate changes between the two periods. Like most electric and natural gas utilities, Avista's billed revenue varies significantly with the weather. Ninety seven percent (97%) of revenue in 2017 was collected from Rate Groups 1 and 2, and subject to the decoupling tariff tracker (Schedule 175). Total revenue and Schedule 175 revenue are shown in Table 2-13 for these three customer classes. Schedule 175 revenue is the revenue collected through the decoupling adjustment mechanism.

Table 2-13. Annual Decoupling Tariff Revenue by Natural Gas Customer Class

	2016			2017		
Natural Gas Customer Class	**Revenue**	**Schedule 175 Revenue**	**Percent of Bill**	**Revenue**	**Schedule 175 Revenue**	**Percent of Bill**
G1: Residential	102,988,637	614,363	0.6%	123,005,058	4,499,375	3.7%
G2A: General Services	31,098,227	162,110	0.5%	35,230,221	1,253,729	3.6%
G2B: Large General Services	2,441,368	13,015	0.5%	2,467,144	94,787	3.8%

In 2016 Schedule 175 revenue amounted to a small percent of the overall billed revenue in each customer class. Schedule 175 adjustment to rates first took effect on November 1, 2016, muting the annual 2016 impact. The decoupling adjustment amounted to 0.6% of 2016 residential bills. The customer classes in the non-residential rate group (Group 2) experienced a similar Schedule 175 impact, 0.5% of billed revenue. The 3% cap on Schedule 175 impact on rates was hit in both the Residential and Non-residential groups in 2016 (effective November 2016).

Schedule 175 revenue is significantly higher in 2017, the first full calendar year with Schedule 175 in rates. Although still small in percentage of revenue terms, Schedule 175 accounted for 3.7% of billed residential revenue in 2017. The percentage of billed revenue for Group 2 customers was 3.6% for General Services and 3.8% for Large General Services. The 3% cap on Schedule 175 impact on rates was hit in the Residential group but not in the Non-residential groups in 2017 (effective November 2017).

Summarizing impacts annually is useful at a high level but a monthly view is necessary to examine the pattern of usage and impact on bills from the decoupling mechanism. Monthly details are shown by natural gas customer class for 2016 and 2017 in Table 2-14 and Table 2-15, respectively. These tables show total usage, revenue, meters (customers), average usage, average revenue, and Schedule 175 revenue (total, average, and as a percent of revenue) for customer classes subject to the decoupling mechanism.

Monthly revenue impacts follow the pattern of volumetric sales. As a result, customer classes with high seasonality also show high seasonality in the average customer's monthly Schedule 175 charge. Due to weather induced seasonality in monthly usage, the surcharge paid per customer varies significantly by month for the Residential Rate Group, ranging from a low of $0.36 per customer in August 2017 to a high of $6.35 per customer in December 2017.

A review of the monthly data in Table 2-14 and Table 2-15 shows that the percentage impact of Schedule 175 on total revenue also varies with seasonal usage. Because space heating in natural gas homes tends to be a much larger percentage of total annual usage than electrically space heated homes, volumetric charges dominate billed revenue during space heating months and fall off significantly during the summer. In summer months fixed charges make up a larger percentage of billed revenue causing Schedule 175 revenue as a percentage of total revenue to be lower in swing and summer months. In 2017, Schedule 175 revenue in the residential customer class fell from 3.3% of revenue during the winter months of January through March to 2.0% in August 2017.

Table 2-14. 2016 Natural Gas Monthly Billing Data

	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	TOTAL
G1: RESIDENTIAL													
Total Usage (therms)	21,914,729	16,787,450	12,859,745	9,114,929	4,269,068	3,281,704	2,537,766	2,130,642	2,604,714	4,453,518	8,310,385	17,650,621	105,915,271
Total Revenue ($)	18,879,152	15,475,562	12,055,204	8,827,648	4,825,298	4,036,778	3,447,475	3,133,744	3,526,926	5,021,986	8,073,365	15,685,499	102,988,637
Number of Meters	152,912	153,882	153,511	153,360	153,389	153,224	153,459	153,740	154,156	154,684	155,353	155,792	153,955
Avg Usage (therms)	143	109	84	59	28	21	17	14	17	29	53	113	688
Average Revenue ($)	123	101	79	58	31	26	22	20	23	32	52	101	669
Total Schedule 175 Revenue ($)	0	0	0	0	0	0	0	0	0	2	99,281	515,080	614,363
Avg Schedule 175 Revenue ($)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.64	3.31	3.99
Percent of Avg Bill	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%	3.3%	0.6%
G2A: GENERAL SERVICES													
Total Usage (therms)	7,250,293	5,863,761	4,834,415	3,903,602	2,358,421	1,911,146	1,587,532	1,414,488	1,748,018	2,406,577	3,438,048	6,539,758	43,256,059
Total Revenue ($)	4,865,298	4,134,970	3,468,259	2,841,794	1,789,019	1,491,843	1,279,473	1,169,555	1,395,279	1,833,608	2,475,049	4,354,080	31,098,227
Number of Meters	2,642	2,680	2,684	2,773	2,745	2,769	2,770	2,751	2,770	2,775	2,789	2,835	2,749
Avg Usage (therms)	2,744	2,188	1,801	1,408	859	690	573	514	631	867	1,233	2,307	15,738
Average Revenue ($)	1,842	1,543	1,292	1,025	652	539	462	425	504	661	887	1,536	11,314
Total Schedule 175 Revenue ($)	0	0	0	0	0	0	0	0	0	1	31,000	131,109	162,110
Avg Schedule 175 Revenue ($)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.12	46.25	58.98
Percent of Avg Bill	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	3.0%	0.5%
G2B: LARGE GENERAL SERVICES													
Total Usage (therms)	446,020	429,267	364,759	321,617	284,309	246,649	258,436	228,650	254,582	284,516	310,486	281,871	3,711,161
Total Revenue ($)	278,087	280,673	242,268	215,329	192,525	169,507	174,805	156,875	173,252	190,246	236,385	131,418	2,441,368
Number of Meters	22	25	24	24	24	24	24	24	24	23	23	(2)	22
Avg Usage (therms)	20,274	17,171	15,198	13,401	11,846	10,277	10,768	9,527	10,608	12,370	13,499	(140,936)	171,946
Average Revenue ($)	12,640	11,227	10,094	8,972	8,022	7,063	7,284	6,536	7,219	8,272	10,278	(65,709)	113,114
Total Schedule 175 Revenue ($)	0	0	0	0	0	0	0	0	0	0	3,365	9,651	13,015
Avg Schedule 175 Revenue ($)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	146.28	(4,825.30)	603.02
Percent of Avg Bill	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%	7.3%	0.5%

Table 2-15. 2017 Natural Gas Monthly Billing Data

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	TOTAL
G1: RESIDENTIAL													
Total Usage (therms)	28,097,989	22,824,741	17,107,156	11,663,543	7,585,209	3,624,139	2,244,626	1,945,490	2,351,286	5,277,069	11,805,965	18,233,568	132,760,781
Total Revenue ($)	24,698,422	20,121,375	15,196,675	10,587,506	7,285,546	4,192,134	3,126,045	2,905,889	3,213,633	5,429,458	10,536,640	15,711,736	123,005,058
Number of Meters	156,425	156,620	156,919	156,785	156,510	157,170	157,080	157,589	157,973	158,697	159,255	159,738	157,563
Avg Usage (therms)	180	146	109	74	48	23	14	12	15	33	74	114	843
Average Revenue ($)	158	128	97	68	47	27	20	18	20	34	66	98	781
Total Schedule 175 Revenue ($)	822,420	668,118	500,719	341,394	222,020	106,091	65,735	56,956	68,826	154,480	478,139	1,014,478	4,499,375
Avg Schedule 175 Revenue ($)	5.26	4.27	3.19	2.18	1.42	0.68	0.42	0.36	0.44	0.97	3.00	6.35	28.56
Percent of Avg Bill	3.3%	3.3%	3.3%	3.2%	3.0%	2.5%	2.1%	2.0%	2.1%	2.8%	4.5%	6.5%	3.7%
G2A: GENERAL SERVICES													
Total Usage (therms)	9,444,237	8,207,928	6,445,497	4,650,963	3,329,865	2,145,598	1,481,188	1,342,384	1,685,701	2,461,586	4,581,047	6,497,022	52,273,015
Total Revenue ($)	6,154,477	5,390,009	4,289,898	3,159,748	2,317,512	1,562,645	1,145,389	1,064,828	1,269,990	1,743,517	3,023,266	4,108,942	35,230,221
Number of Meters	2,844	2,880	2,894	2,884	2,871	2,921	2,888	2,912	2,896	2,903	2,911	2,950	2,896
Avg Usage (therms)	3,321	2,850	2,227	1,613	1,160	735	513	461	582	848	1,574	2,202	18,049
Average Revenue ($)	2,164	1,872	1,482	1,096	807	535	397	366	439	601	1,039	1,393	12,164
Total Schedule 175 Revenue ($)	200,162	172,991	135,871	98,042	70,191	45,229	31,224	28,297	35,534	52,389	133,916	249,883	1,253,729
Avg Schedule 175 Revenue ($)	70.38	60.07	46.95	34.00	24.45	15.48	10.81	9.72	12.27	18.05	46.00	84.71	432.89
Percent of Avg Bill	3.3%	3.2%	3.2%	3.1%	3.0%	2.9%	2.7%	2.7%	2.8%	3.0%	4.4%	6.1%	3.6%
G2B: LARGE GENERAL SERVICES													
Total Usage (therms)	356,929	400,577	360,847	311,334	338,174	296,350	244,988	257,190	278,472	237,472	410,283	395,787	3,888,404
Total Revenue ($)	225,855	250,051	227,237	198,771	217,471	189,073	158,936	166,123	178,610	157,864	282,153	214,999	2,467,144
Number of Meters	22	22	22	22	25	25	25	25	24	24	25	(2)	22
Avg Usage (therms)	16,224	18,208	16,402	14,152	13,527	11,854	9,800	10,288	11,603	9,895	16,411	(197,893)	180,158
Average Revenue ($)	10,266	11,366	10,329	9,035	8,699	7,563	6,357	6,645	7,442	6,578	11,286	(107,500)	114,308
Total Schedule 175 Revenue ($)	8,374	8,444	7,607	6,563	7,129	6,247	5,164	5,422	5,870	5,006	12,708	16,253	94,787
Avg Schedule 175 Revenue ($)	380.64	383.83	345.76	298.32	285.15	249.88	206.57	216.86	244.59	208.58	508.34	(8,126.30)	4,391.66
Percent of Avg Bill	3.7%	3.4%	3.3%	3.3%	3.3%	3.3%	3.2%	3.3%	3.3%	3.2%	4.5%	7.6%	3.8%

The months of November and December can also show significant differences in Schedule 175 revenue percentage from preceding months. This is due to the November 1 effective date of new Schedule 175 rate adjustments. For example, the Schedule 175 percent for the General Services class went from 3.0% in October 2017 to 6.1% in December 2017 as the new Schedule 175 rate effective November 1, 2017 became fully reflected in customer bills.[30] In order to visualize and contrast the impacts on customer natural gas revenues between customer classes, the percentage of monthly natural gas revenues attributed to Schedule 175 from the time rates were first impacted by the decoupling mechanism through December 2017 is shown in Figure 2-9.

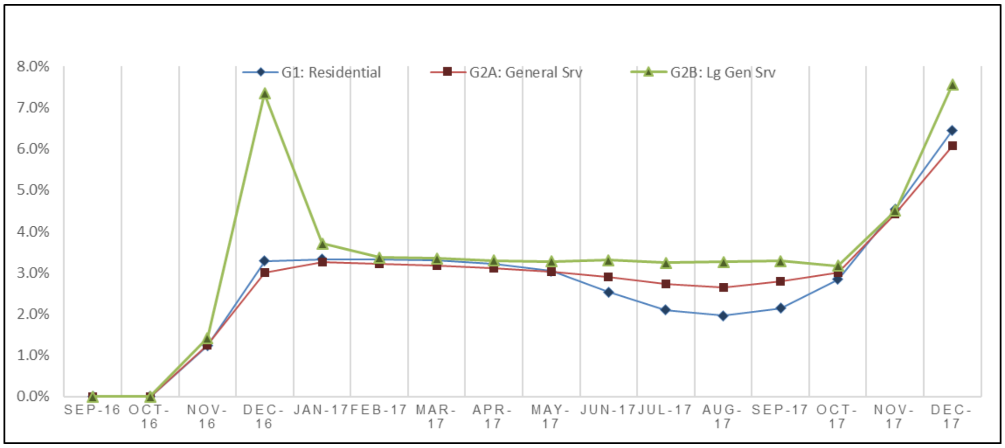


Figure 2-9. Schedule 175 as a Percent of Monthly Customer Class Revenues

Figure 2-9 shows monthly Schedule 175 revenue as a percentage of total revenue for each customer class subject to decoupling. The impact on revenue of the first decoupling tariff adjustment effective November 1, 2016 can be seen beginning with November 2016 billed revenue. Residential customers saw the partial impact of Schedule 175 in November 2016 and the full impact in December 2016 with Schedule 175 revenue accounting for 3.3% of revenue. Schedule 175 revenue as a percent of class revenue increased again with new rates effective November 1, 2017. In incremental percentage terms, the 2017 increase was nearly the same as the 2016 increase in Schedule 175 revenue. In December 2017 when the full impact of the second year decoupling adjustment is reflected in rates, Residential Schedule 175 revenues were 6.5% of total revenue, 3.2 percentage points higher than the first rate adjustment revenue impact in December 2016. Schedule 175 was limited by the 3% annual cap in both the first rate year and the second, resulting in the similar incremental increase in Schedule 175 revenue percentage in both years.

For Group 2 (non-residential) customer classes, Schedule 175 was also about 3% of total revenue with the first rate year adjustment (effective November 1, 2016). On a monthly basis in 2017, the impact of Schedule 175 as percentage of total revenue averaged 3.6% for General Services with lower amounts in the summer months and a similar incremental increase in the second rate

[30] Although the effective date of revised Schedule 175 rates was November 1, customer bills in November reflect usage that is partially billed at the old Schedule 175 rate and part billed at the new Schedule 175 rate. The portion billed under the old and new rates is determined by a simple prorating of usage based on the number of calendar days in the billing period before November 1 and the number of days on or after November 1.

year. The 3% rate cap limited the Non-Residential Schedule 175 rate the first rate year (effective November 1, 2016) but was not a factor in the second rate year (effective November 1, 2017). The spike shown in Figure 2-9 for Large General Service customers in December 2016 and December 2017 is due to retroactive bill adjustments that lowered the total revenue for these customers, resulting in a jump in Schedule 175 revenue as a percent of total revenue. The small number (around two dozen) of large customers in this group can lead to large changes overtime when compared to other customer classes.

Task 2 Part 2: Are Allowed Revenues Recovering Cost of Service by Rate Group?

The objective for the second part of Task 2 as stated in the request for proposal, is shown below:

> *"This assessment must include an analysis detailing if allowed revenues from the residential, non-residential, and customers not subject to decoupling rate classes are recovering their respective costs of service."*

Relating to this objective is the following evaluation question, also taken from the RFP:

> *"Are the allowed revenues from the residential class, non-residential class, and customers not subject to decoupling recovering their cost of service?"*

For this analysis it is necessary to show annual calendar revenues and cost of service for each of the three rate groups; residential, non-residential and non-decoupled. Revenue details are fairly straightforward and are determined by base rate revenue and revenues deferred through the decoupling mechanism. Avista provided detailed electric and natural gas cost of service workbooks showing revenue and cost calculations for the three rate groups.[31] Actual cost allocations are based on allocation factors in cost of service studies provided in the general rate case (GRC) proceedings adjusted for actual usage and customer counts in each calendar year. GRC values for rates and cost of service changed between the first decoupled year (2015) and the last two years (2016 and 2017).[32] This shift in assumptions may result in strange relationships in the analysis of actual revenue and cost of service.

Results of this analysis are shown in Table 2-16 for electric and Table 2-17 for natural gas. Both tables are structured the same and begin with lines showing base rate revenue (line 1) and revenue from decoupling deferrals (line 2) over the calendar year. Total revenue is the sum of each of these revenue types. Cost of service is broken down by production and transmission (electric)/underground-storage (natural gas), distribution and customer services, and administrative and general expenses. Production and transmission/underground-storage expenses are further broken out between fixed and variable costs. Variable production and transmission costs for electric (Table 2-16, line 4) are defined as volumetric sales to each rate group multiplied by the retail revenue credit (cost per kWh). Variable production and

[31] See Avista response to Data Request number 89.
[32] See Table 1-1 for the electric and natural gas GRC in effect for a given year.

underground-storage costs for natural gas (Table 2-17, line 4) are defined by the applicable Weighted Average Cost of Gas (WACOG) rates from Schedule 150 multiplied by therm sales.

Net operating income is shown on line 11 and is derived by subtracting operating expenses (line 8) and income taxes (line 10) from total revenue (line 3). The earnings test rate of return (line 13) is calculated by dividing net operating income (line 11) by the rate base (line 12). The return ratio (line 14) shows the rate of return for the rate group relative to the overall rate of return for the calendar year. For comparison purposes, line 15 shows the return ratio from the applicable GRC settlement.

The allowed return on rate base is shown as an expense on line 16 and is calculated at unity (i.e. the allowed rate of return is achieved for each customer class). Other expenses related to allowed return on rate base, taxes and revenue related expenses, are also included in line 16. Total allowed cost at unity (line 17) is the sum of all expenses (lines 8, 10 and 16). The revenue over (excess) or under (shortfall) allowed costs is shown on line 18 and is calculated by subtracting total costs (line 17) from total revenue (line 3).

Various revenue-to-cost ratios are shown at the bottom of Table 2-16 and Table 2-17. Line 19 shows the actual revenue-to-cost ratio for each rate group and calendar year and is calculated by dividing total revenue (line 3) by total cost (line 17). The corresponding relative revenue-to-cost parity ratio (line 20) shows the revenue-to-cost ratio for the rate group relative to the overall revenue-to-cost ratio for the calendar year. For comparison purposes, line 15 shows the allowed revenue-to-cost ratio from the applicable GRC.

Readers can more easily understand the findings of this section by focusing attention on two areas of results in Table 2-16 and Table 2-17. First, determine if revenues exceeded all costs and, next, determine if the result was as planned given the structure of rates and costs in the applicable GRC. First, we are able to quickly determine if revenues for the system and each rate group were sufficient to cover all costs by looking at excess revenue (line 18). If excess revenue is positive then revenue exceeded all costs, including the allowed ROR on rate base. If excess revenues are negative then costs exceeded revenue. The revenue to cost ratio (line 19) shows the same relationship and can also be used to determine if revenues exceeded costs (line 19 is greater than 1.00) or fell short of costs (line 19 is less than 1.00).

The other area of results we draw the reader's attention to provides understanding of whether or not the observed excess or shortfall in revenue was expected (i.e. planned) given the rates and costs in the applicable GRC. This can quickly be determined by comparing actual results of the revenue to cost ratio (line 19) to the GRC allowed revenue to cost ratio (line 21). If line 19 is equal to line 21 then actual results were as planned by the GRC. When line 19 exceeds line 21 results were better than planned and, conversely, when line 19 is less than line 21 actual results were worse than planned.

We begin our analysis and reporting for this task with electric rate groups followed by natural gas rate groups. Within the electric and natural gas sub-sections below, we organize our discussion by rate group across the three years rather than by year across rate groups to highlight any trends within rate groups.

Electric

An examination of the electric revenues and cost of service analysis summarized in Table 2-16 reveals that Avista's Washington electric system revenue exceeded total costs in all three years. As reported elsewhere in this report, these excess earnings are shared with decoupled customer groups. Overall the non-residential rate group subsidizes the residential rate group and, to a much lesser extent, the non-decoupled rate group. These cross-subsidization results are consistent with GRC expectations.

Electric residential customers have a revenue shortfall in each year and that shortfall (subsidy) has increased since 2015. The subsidy to residential is an artifact of the GRC as is the increasing level of subsidy. The GRC allowed revenue to cost ratio for electric residential was 0.89 in 2015 and 0.87 in 2016 and 2017. Although the actual revenue to cost ratio slightly exceeded these values, the subsidy to residential customers was mostly as planned.

The electric non-residential rate group experienced increasingly higher levels of excess revenue over the 2015 to 2017 period. Comparing the actual revenue to cost ratio with the GRC allowed revenue to cost ratio shows that the excess revenue was expected at nearly the same levels as experienced. The non-residential rate group has slightly exceeded GRC expectations in 2016 and 2017.

The electric non-decoupled rate group has received a slight subsidy (revenue shortfall). The subsidy has decreased between 2015 and 2017. The subsidy and decline in subsidy were as planned by the GRC with GRC allowed revenue to cost ratios moving from 0.96 in 2015 to 0.99 in 2016 and 2017.

Natural Gas

An examination of natural gas revenues and cost of service analysis summarized in Table 2-17 reveals that Avista's Washington natural gas system had a revenue shortfall in 2015 and a surplus in 2016 and 2017. Unlike the electric system, excess revenue surpluses and shortfalls have not been consistent across the three years or within rate groups. The change in GRC assumptions between 2015 and 2016/2017 appears to have materially shifted actual and planned earnings results for all rate groups. The difference between actual and planned performance across each year and rate group has also been material. However, on a relative basis as measured by the relative revenue to cost parity ratio (line 20) the performance between rate groups has been as planned (comparing lines 20 and 21) except for the non-decoupled rate group.

After receiving a larger than planned subsidy (revenue shortfall) in 2015, the natural gas residential rate group experienced a small level of excess revenue in 2016 and an even smaller (in absolute value terms) level of revenue shortfall in 2017. Combined excess revenue for 2016 and 2017 is only slightly greater than zero meaning that revenue from residential customers are just covering all costs. This is slightly better than the expected subsidy to residential customers based on the GRC allowed revenue to cost ratio of 0.97.

The non-residential natural gas rate group essentially broke even in 2015 with a small level of excess revenue (revenue to cost ratio equal to 1.00). Excess revenue increased in 2016 and 2017 to over 5 million dollars that when considered with allowed costs results in a revenue to cost ratio of 1.17 for 2016 and 1.16 2017. The sharp increase in revenue to cost ratio from 1.00 in 2015 was largely although not totally planned. The GRC allowed revenue to cost ratio went from 1.04 in 2015 to 1.12 for 2016 and 2017. Actual performance of 1.17 and 1.16 in 2016 and 2017, respectively, outpaced planned performance of 1.12 for these years.

Excess revenue in the non-decoupled natural gas rate group experienced a shortfall in 2015 and 2016 but was slightly positive in 2017. The 2015 shortfall corresponded to a revenue to cost ratio of 0.89 and was largely unplanned. The GRC allowed revenue to cost ratio for 2015 of 0.99 was much higher than the actual value of 0.89. Actual performance, as measured by the revenue to cost ratio, in 2016 and 2017 steadily improved from 2015 levels. This improvement was largely unplanned considering the GRC approved revenue to cost ratio in effect for 2016 and 2017 was 0.91 and actual results were 0.94 in 2016 and 1.02 in 2017.

Table 2-16. Electric Revenues and Cost of Service by Rate Group (thousands of dollars)

		2015				2016				2017			
Row	**Item**	**Total**	**Residential**	**Non-Residential**	**Non-Decoupled**	**Total**	**Residential**	**Non-Residential**	**Non-Decoupled**	**Total**	**Residential**	**Non-Residential**	**Non-Decoupled**
1	Base Rate Revenue	497,677	210,034	216,152	71,491	485,974	203,623	211,142	71,209	506,932	222,080	213,180	71,672
2	Decoupling Deferred Revenue	4,795	7,168	(2,373)	0	12,256	10,288	1,968	0	(357)	(2,093)	1,736	0
3	**Total Revenue**	**502,472**	**217,202**	**213,779**	**71,491**	**498,230**	**213,911**	**213,110**	**71,209**	**506,575**	**219,987**	**214,916**	**71,672**
	Production and Transmission Expenses												
4	Variable	113,158	46,745	43,856	22,557	88,146	36,157	34,115	17,873	91,100	39,029	34,215	17,856
5	Fixed	96,016	44,317	35,404	16,295	102,148	46,485	38,391	17,271	102,863	48,774	37,371	16,718
6	Distribution & Customer Services Expenses	87,863	46,658	32,894	8,311	87,628	47,878	31,365	8,384	89,071	49,177	31,442	8,453
7	Administrative and General Expenses	71,444	37,099	24,711	9,634	72,851	38,529	24,682	9,640	72,184	38,252	24,254	9,678
8	**Sub-Total Expenses**	**368,481**	**174,819**	**136,865**	**56,797**	**350,773**	**169,051**	**128,554**	**53,168**	**355,218**	**175,233**	**127,281**	**52,704**
9	Income Before Income Tax	133,991	42,383	76,914	14,694	147,457	44,861	84,556	18,040	151,357	44,754	87,635	18,968
10	Income Tax Expenses	34,877	8,792	22,567	3,518	39,052	9,156	25,294	4,602	39,155	8,371	25,976	4,808
11	**Net Operating Income**	**99,114**	**33,592**	**54,347**	**11,175**	**108,405**	**35,704**	**59,262**	**13,438**	**112,202**	**36,383**	**61,659**	**14,160**
12	Rate Base	1,338,806	657,459	502,553	178,794	1,442,726	714,182	534,277	194,266	1,513,706	764,429	549,839	199,438
13	Earnings Test Rate of Return	7.40%	5.11%	10.81%	6.25%	7.51%	5.00%	11.09%	6.92%	7.41%	4.76%	11.21%	7.10%
14	Return Ratio	1.00	0.69	1.46	0.84	1.00	0.67	1.48	0.92	1.00	0.64	1.51	0.96
15	GRC Return Ratio	1.00	0.67	1.48	0.88	1.00	0.62	1.50	0.98	1.00	0.62	1.50	0.98
16	Allowed Return on Rate Base plus Related Expenses	97,316	57,060	25,993	14,263	103,211	62,115	26,488	14,609	109,215	67,563	26,881	14,771
17	Total Allowed Cost at Unity	500,674	240,671	185,424	74,579	493,036	240,321	180,336	72,379	503,589	251,167	180,138	72,284
18	**Excess (Shortfall) Revenue**	**1,798**	**(23,469)**	**28,355**	**(3,088)**	**5,194**	**(26,410)**	**32,775**	**(1,171)**	**2,987**	**(31,180)**	**34,778**	**(611)**
19	Revenue to Cost Ratio	1.00	0.90	1.15	0.96	1.01	0.89	1.18	0.98	1.01	0.88	1.19	0.99
20	Relative Revenue to Cost Parity Ratio	1.00	0.90	1.15	0.96	1.00	0.88	1.17	0.97	1.00	0.87	1.19	0.99
21	GRC Allowed Revenue to Cost Ratio	1.00	0.89	1.16	0.96	1.00	0.87	1.17	0.99	1.00	0.87	1.17	0.99

Table 2-17. Natural Gas Revenues and Cost of Service by Rate Group (thousands of dollars)

Row	Item	2015 Total	2015 Residential	2015 Non-Residential	2015 Non-Decoupled	2016 Total	2016 Residential	2016 Non-Residential	2016 Non-Decoupled	2017 Total	2017 Residential	2017 Non-Residential	2017 Non-Decoupled
1	Base Rate Revenue	141,717	103,106	35,543	3,069	142,618	105,157	34,044	3,417	165,706	123,511	38,296	3,900
2	Decoupling Deferred Revenue	7,048	5,311	1,737	0	9,156	7,153	2,003	0	(1,132)	(1,972)	840	0
3	**Total Revenue**	**148,765**	**108,417**	**37,280**	**3,069**	**151,774**	**112,310**	**36,047**	**3,417**	**164,575**	**121,539**	**39,136**	**3,900**
	Production and Transmission Expenses												
4	Variable	69,498	47,565	21,513	420	58,186	40,208	17,650	328	66,528	46,691	19,517	321
5	Fixed	2,234	1,511	679	44	2,577	1,750	777	49	2,519	1,738	735	46
6	Distribution & Customer Services Expenses	35,625	29,159	5,601	866	36,470	29,627	5,513	1,330	38,631	31,287	5,942	1,402
7	Administrative and General Expenses	17,288	12,448	3,687	1,153	20,388	17,606	2,224	558	20,883	17,947	2,357	578
8	**Sub-Total Expenses**	**124,645**	**90,682**	**31,480**	**2,483**	**117,620**	**89,191**	**26,164**	**2,265**	**128,561**	**97,662**	**28,551**	**2,347**
9	Income Before Income Tax	24,120	17,734	5,800	586	34,154	23,119	9,883	1,152	36,014	23,876	10,585	1,553
10	Income Tax Expenses	7,336	5,274	1,913	150	9,630	6,216	3,131	283	9,957	6,218	3,325	414
11	**Net Operating Income**	**16,783**	**12,461**	**3,887**	**436**	**24,524**	**16,903**	**6,751**	**869**	**26,057**	**17,659**	**7,260**	**1,138**
12	Rate Base	272,971	210,944	52,992	9,035	286,597	224,256	48,517	13,824	313,174	244,878	53,335	14,961
13	Earnings Test Rate of Return	6.15%	5.91%	7.33%	4.82%	8.56%	7.54%	13.92%	6.29%	8.32%	7.21%	13.61%	7.61%
14	Return Ratio	1.00	0.96	1.19	0.78	1.00	0.88	1.63	0.73	1.00	0.87	1.64	0.91
15	GRC Return Ratio	1.00	0.94	1.25	0.96	1.00	0.87	1.65	0.82	1.00	0.87	1.65	0.82
16	Allowed Return on Rate Base plus Related Expenses	21,946	17,272	3,874	800	18,669	16,011	1,566	1,093	20,857	17,970	1,826	1,061
17	Total Allowed Cost at Unity	153,928	113,228	37,267	3,433	145,919	111,417	30,861	3,641	159,375	121,850	33,702	3,823
18	**Excess (Shortfall) Revenue**	**(5,163)**	**(4,811)**	**13**	**(364)**	**5,855**	**893**	**5,186**	**(224)**	**5,200**	**(311)**	**5,434**	**77**
19	Revenue to Cost Ratio	0.97	0.96	1.00	0.89	1.04	1.01	1.17	0.94	1.03	1.00	1.16	1.02
20	Relative Revenue to Cost Parity Ratio	1.00	0.99	1.04	0.93	1.00	0.97	1.12	0.90	1.00	0.97	1.12	0.99
21	GRC Allowed Revenue to Cost Ratio	1.00	0.99	1.04	0.99	1.00	0.97	1.12	0.91	1.00	0.97	1.12	0.91

Summary - Task 2

Impacts of decoupling on customer bills have been small over the first three calendar years of operation, partly due to the timing of billing impacts. The last year of the period, 2017, was the only year with the decoupling rate in effect for all 12 months. The impact of the decoupling rate on electric bills ranged from a reduction of 1.7 % for the pumping customer class to an increase of 3.0% for the residential customer class. Monthly impacts in November and December of 2017 reflect the latest change to decoupling rates and show increases in the residential rate group to 4.6% of customer bills and around 0.3% for the non-residential rate group.

The annual impact on natural gas customer bills followed a slightly higher path than electric due to greater exposure to the impacts of heating degree days on natural gas usage and deferral balances. Still, the impact on annual natural gas bills was small and nearly the same for all customer classes, around one half of one percent in 2016 and around 3.7% in 2017. The pattern of monthly impacts shows that the greatest impact on customer bills occurred at the end of 2017 when new decoupling rates took effect November 1, 2017. With the new decoupling rates, we expect calendar year 2018 natural gas bill impacts to be around 6% for both natural gas rate groups, residential and non-residential.

An important characteristic of the Avista decoupling mechanism is that the possibility of ever-increasing levels of carryover deferrals (snow-balling deferral balances) is greatly reduced by allowing the decoupling rate to adjust incrementally higher each rate year, subject to the annual 3% cap. This feature limits rate shock while also allowing the decoupling rate to amortize higher levels of requested recovery. At some point, even if weather or other conditions that caused initially high deferral carryovers persist, the decoupling rate will eventually adjust to a level that recovers 100 percent of requested recovery and carryover deferral balances will fall to zero.

An assessment to determine if allowed revenues from the residential, non-residential, and customers not subject to decoupling rate classes are recovering their respective costs of service shows significantly different results for electric and natural gas. Avista’s Washington electric system revenue exceeded total costs in all three years. Overall the non-residential rate group subsidizes the residential rate group and, to a much lesser extent, the non-decoupled rate group. These cross-subsidization results are consistent with GRC expectations. Avista’s Washington natural gas system had a revenue shortfall in 2015 and a surplus in 2016 and 2017. Unlike the electric system, revenue surpluses and shortfalls have not been consistent across the three years or within rate groups. The change in natural gas GRC assumptions between 2015 and 2016/2017 appears to have materially shifted actual and planned earnings results for all rate groups.

Section 3. Low-Income Analysis and Contrasts

This section provides an evaluation of trends in Low-Income Bill Assistance and the Low-Income Weatherization services during the study period (2012-2014 and 2015-2017). The billing analysis compares data for the three-year period immediately preceding decoupling to the three-year period following decoupling implementation to identify any changes. Other analysis covers time since the inception of the decoupling mechanism.

> Task 3: An assessment of the impact of the Mechanisms specifically on Avista's low-income customers. The known low-income population to Avista are those customers who have received bill payment assistance through Avista's Low-Income Rate Assistance Program ("LIRAP"), energy efficiency services funded by Avista's electric and/or natural gas energy efficiency programs, or the Federal LIHEAP program. Cognizant that a larger portion of the low-income population do not participate in the three programs referenced above, the Consultant is encouraged to use other available information, such as the information provided in Attachments G and H to this RFP, to better determine the impact on all Avista's low-income customers. The assessment should include: (3a-3e)
>
> (3a) A summary of the annual deferrals and rate impacts of the Decoupling tariff tracker adjustments (cents per kWh, cents per therm, total dollars, and percent of monthly bills) on the group of customers receiving bill payment assistance through the above-referenced low-income programs.
>
> (3b) A summary of annual low-income conservation program savings, expenditures and customers served compared with the rest of the residential class, where low-income conservation programs are defined as the programs currently being run under Electric Schedule 90 and Natural Gas Schedule 190.
>
> (3c) A description of any modifications to conservation programs targeted to low-income customers since the inception of the Mechanisms including changes to funding levels as well as changes to specific measures.
>
> (3d) A comparison of the effect of the Decoupling tariff tracker adjustment on the average customer receiving bill payment assistance through the above-referenced low-income programs relative to the impact on Avista's average residential customer.
>
> (3e) To the extent data is available, Consultant should evaluate other factors such as household size, housing stock (e.g. mobile home, multifamily) and heat source (e.g., electric space heat) and the effect of seasonality when comparing the impact of decoupling on low-income customers versus other customer groups (such as average residential customers).

Figure 3-1. The Parts of Task 3

Low-Income Billing Impacts (includes Parts A and D)

In this section we examine the billing impacts of the decoupling tracker adjustment for low-income customers. We also contrast those impacts with the residential customer class. To facilitate communication, we report here on both Part A and Part D of Task 3.

The objective of Task 3 Part A, as stated in the Request for Proposal (RFP), is shown below:

> *"A summary of the annual deferrals and rate impacts of the Decoupling tariff tracker adjustments (cents per kWh, cents per therm, total dollars, and percent of monthly bills) on the group of customers receiving bill payment assistance through the above-referenced low-income programs"*

The "above-referenced programs" are addressed at the outset of this section. The objective of Task 3 Part D, as stated in the request for proposal, is shown below:

> *"A comparison of the effect of the Decoupling tariff tracker adjustment on the average customer receiving bill payment assistance through the above-referenced low-income programs relative to the impact on Avista's average residential customer."*

Relating to these objectives is the following evaluation question, also taken from the RFP:

> *"On average, were there any differences in the annual Decoupling deferrals and tariff tracker adjustment impacts between low-income customers and residential customers?"*

A good place to start the discussion is with the question of how to define Avista's low-income customers. Because this section relies on customer billing records, it is important to have a definition of low-income that can be applied to the customer information system. Avista refers to this group in the RFP for this evaluation as the "known low-income population and includes customers who have received bill payment assistance through Avista's Low-Income Rate Assistance Program ("LIRAP"), energy efficiency services funded by Avista's electric and/or natural gas energy efficiency programs, or the Federal LIHEAP program"[33]. These are the programs referred to in the "above-referenced programs" quote from the RFP above.

For the purposes of this section, we use the known low-income population for analysis and comparison to the residential customer class. Avista pulled account-specific billing records for low-income customers. Customer usage and revenue information was included for billing periods for which the customer participated in one or more low-income programs. Annual average low-income customer counts summarized from the account level data provided are shown in Table 3-1 below. Total residential customer counts as reported in Section 2 are also shown in the table.

[33] It is understood that the low-income population is much larger than the participants in the referenced programs. See Section 8, the low-income appendix for discussion and analysis of broader definitions of low-income.

Table 3-1. All Residential and Low-Income Electric and Natural Gas Customer Counts

	Electric			Natural Gas		
Year	Residential	Low-Income	Percent	Residential	Low-Income	Percent
2012	202,541	31,539	16%	146,776	14,441	10%
2013	203,883	31,343	15%	147,880	14,341	10%
2014	205,621	31,525	15%	149,453	14,104	9%
2015	209,419	32,793	16%	152,182	14,208	9%
2016	209,864	33,088	16%	153,955	14,449	9%
2017	212,495	31,782	15%	157,563	14,189	9%

The number of low-income customers on the electric system has varied narrowly between 31 and 33 thousand customers.[34] This amounts to 15 percent to 16 percent of the total residential customer class. Avista's natural gas system has served over 14 thousand customers annually since 2012, about 9 percent of the residential customer class.

Our reporting and analysis of deferral balances and decoupling tariff tracker adjustments (decoupling rates) for low-income customers, including a comparison to the residential customer class on average, is organized by electric and natural gas service.

Impact on Electric Low-Income Customers

Customer usage is an important driver in most utility operations and financial results, including decoupling deferral balances and decoupling rates. Figure 3-2 shows electric use per customer for all residential and low-income customers.

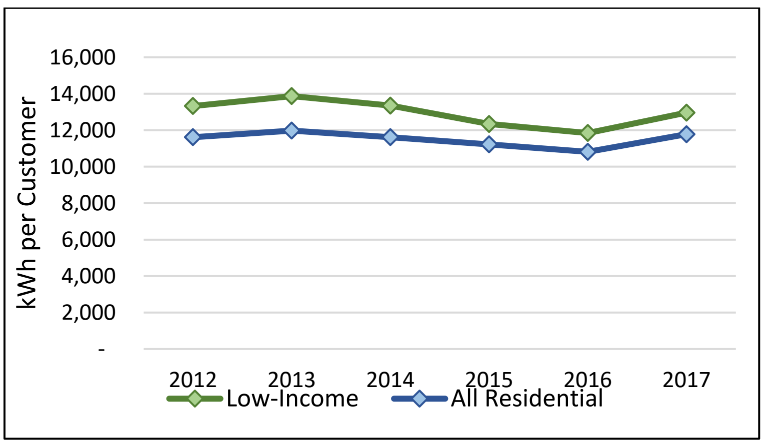


Figure 3-2. Annual Electric Use per Customer, Low-Income and All Residential

Electric usage per low-income customer is distinctly higher than for the average residential customer. This difference appears to have narrowed over time, most likely due to conservation programs for low-income customers, including conversions to natural gas heat. Low-income use per customer averaged about 10 percent higher than average residential usage between 2015 and 2017. This means that low-income customers will have a 10 percent greater exposure (higher rebates and surcharges) to the decoupling rate (Schedule 75) than the average residential

[34] References to the Avista system refer to operations in the state of Washington, the scope of this evaluation.

customer. Possible explanations for higher use per customer in low-income residences are explored in Section 3 Part E, below.

Energy conservation programs are most likely the driver behind the narrowing gap between use per low-income customers and all residential customers shown in Figure 3-2. A relatively greater level of conservation savings in the low-income customer group relative to all residential would lead to the declining difference observed in the historical data. Considering just 2017, first year conservation savings for low-income customers amounted to 1.7 percent of usage while first year conservation savings for all residential was 1.3 percent.[35] The low-income conservation effort is also using conversions from electric space and water heating to natural gas at higher levels than all residential. In 2017 low-income conversions accounted for 73 percent of first year savings compared to 31 percent for all residential.

Average customer revenue and decoupling revenue (Schedule 75) is shown in Table 3-2 below.

Table 3-2. Comparison of Average Annual Electric Revenue per Customer

Residential Group	**2016**			**2017**		
	Revenue	Schedule 75 Revenue	Percent of Bill	Revenue	Schedule 75 Revenue	Percent of Bill
Low-Income	$ 1,116	$ 4.33	0.4%	$ 1,268	$ 37.02	2.9%
All Residential	$ 988	$ 3.91	0.4%	$ 1,116	$ 33.73	3.0%
Difference	$ 127	$ 0.41	0.0%	$ 152	$ 3.28	-0.1%

As explained in Section 2, deferral rates first became effective November 1, 2016. Decoupling impacts on revenues in 2016 are small because the first decoupling tariff tracker adjustment did not become effective in rates until November 1, 2016. In 2017 Schedule 75 accounted for about 3 percent of the revenue from each residential group. On a percentage of bill basis, there is no meaningful difference between low-income and all residential.[36] However, low-income customers paid just over $37 in Schedule 75 charges in 2017, $3.28 more after rounding than all residential. This is consistent with higher use per customer of low-income customers. Electric low-income customers will also receive a larger rebate than all residential when Schedule 75 is negative.

Monthly usage and revenue details for the two residential groups are shown in Table 3-3 for 2016 and 2017. The data for all residential is the same as reported in Section 2, repeated here for ease of comparison to low-income customers.

Schedule 75 revenue varies with the prevailing rate and the pattern of monthly usage. Average monthly payments are shown in Figure 3-3 for both residential groups.

In 2017 the average low-income customer paid a low of $2.01 in June to a high of $5.76 in December with higher winter usage and the new higher Schedule 75 rate effective November 1,

[35] Conservation program information referenced here is taken from Section 6 of this report where the impact of conservation programs is discussed in greater detail.
[36] Electric low-income customers show Schedule 75 revenue to be a slightly smaller percentage of the total bill.

2017. The impact of higher use per customer on Schedule 75 revenue is also evident in the chart with payments from low-income customers averaging $0.27 a month higher than all residential.

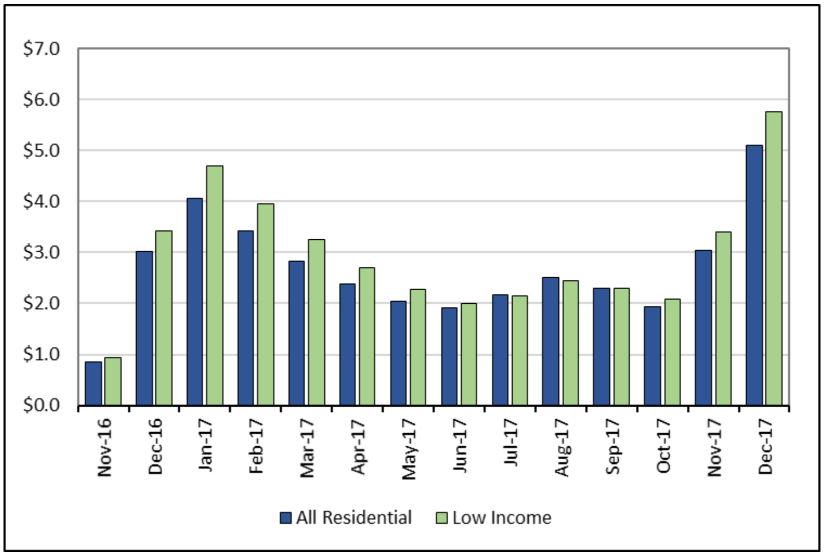


Figure 3-3. Comparison of Average Monthly Electric Schedule 75 Revenue per Customer

Table 3-3. Monthly Electric Usage, Meters and Revenue, Low-Income and All Residential

	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	TOTAL
ALL RESIDENTIAL													
Total Usage (kWh)	281,027,480	230,506,821	198,363,507	175,201,661	148,495,652	154,090,137	163,425,633	176,921,758	176,555,296	148,062,106	171,637,794	244,773,659	2,269,061,504
Total Revenue ($)	25,630,827	20,881,166	17,916,278	15,817,614	13,485,159	13,978,673	14,848,991	16,154,290	16,160,405	13,635,478	15,857,718	23,038,434	207,405,033
Number of Meters	208,217	210,418	209,750	209,405	209,004	208,965	209,204	209,512	210,314	210,674	211,346	211,562	209,864
Avg Usage (kWh)	1,350	1,095	946	837	710	737	781	844	839	703	812	1,157	10,812
Average Revenue ($)	123	99	85	76	65	67	71	77	77	65	75	109	988
Total Schedule 75 Revenue ($)	0	0	0	0	0	0	0	0	0	8	181,297	639,882	821,187
Avg Schedule 75 Revenue ($)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.86	3.02	3.91
Percent of Avg Bill	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	2.8%	0.4%
LOW-INCOME RESIDENTIAL													
Total Usage (kWh)	51,792,825	42,246,732	36,334,392	31,460,899	25,482,967	25,433,162	26,106,262	27,736,360	27,849,606	24,587,805	29,744,142	43,039,640	391,814,792
Total Revenue ($)	4,908,225	3,959,794	3,382,484	2,919,017	2,372,729	2,367,074	2,438,539	2,605,931	2,624,172	2,321,419	2,822,765	4,187,153	36,909,302
Number of Meters	33,094	33,250	33,390	33,373	33,323	33,262	33,051	32,953	32,822	32,807	32,843	32,882	33,088
Avg Usage (kWh)	1,565	1,271	1,088	943	765	765	790	842	849	749	906	1,309	11,842
Average Revenue ($)	148	119	101	87	71	71	74	79	80	71	86	127	1,116
Total Schedule 75 Revenue ($)	0	0	0	0	0	0	0	0	0	1	30,784	112,384	143,170
Avg Schedule 75 Revenue ($)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.94	3.42	4.33
Percent of Avg Bill	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	2.7%	0.4%

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	TOTAL
ALL RESIDENTIAL													
Total Usage (kWh)	328,204,493	275,264,984	227,842,125	191,579,775	164,336,749	154,995,685	174,494,045	202,126,296	185,654,057	158,083,535	193,502,303	246,386,721	2,502,470,768
Total Revenue ($)	31,350,022	26,114,270	21,484,843	17,986,535	15,471,354	14,643,313	16,410,432	19,007,693	17,533,688	14,994,830	18,396,962	23,724,868	237,118,808
Number of Meters	212,134	212,059	212,618	212,018	211,258	211,830	211,439	212,411	212,339	213,798	213,856	214,177	212,495
Avg Usage (kWh)	1,547	1,298	1,072	904	778	732	825	952	874	739	905	1,150	11,777
Average Revenue ($)	148	123	101	85	73	69	78	89	83	70	86	111	1,116
Total Schedule 75 Revenue ($)	863,088	723,914	599,203	503,828	432,218	407,643	458,821	531,604	488,277	415,771	650,764	1,093,219	7,168,350
Avg Schedule 75 Revenue ($)	4.07	3.41	2.82	2.38	2.05	1.92	2.17	2.50	2.30	1.94	3.04	5.10	33.73
Percent of Avg Bill	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	3.5%	4.6%	3.0%
LOW-INCOME RESIDENTIAL													
Total Usage (kWh)	58,734,312	49,295,700	40,591,195	33,534,017	28,021,392	24,588,795	25,980,235	29,336,020	27,138,379	24,397,403	31,080,870	39,248,667	411,946,985
Total Revenue ($)	5,822,267	4,844,930	3,951,217	3,241,125	2,708,450	2,386,460	2,515,190	2,842,472	2,644,188	2,377,756	3,043,320	3,910,652	40,288,025
Number of Meters	32,813	32,738	32,759	32,621	32,431	32,181	31,801	31,528	31,034	30,757	30,501	30,214	31,782
Avg Usage (kWh)	1,790	1,506	1,239	1,028	864	764	817	930	874	793	1,019	1,299	12,962
Average Revenue ($)	177	148	121	99	84	74	79	90	85	77	100	129	1,268
Total Schedule 75 Revenue ($)	154,388	129,610	106,721	88,193	73,695	64,646	68,329	77,155	71,374	64,164	103,987	174,161	1,176,423
Avg Schedule 75 Revenue ($)	4.71	3.96	3.26	2.70	2.27	2.01	2.15	2.45	2.30	2.09	3.41	5.76	37.02
Percent of Avg Bill	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	3.4%	4.5%	2.9%

Impact on Natural Gas Low-Income Customers

As with electric, due to the influence of use per customer on decoupling deferrals, we begin our discussion of natural gas with a comparison between low-income and all residential use per customer. Figure 3-4 shows natural gas use per customer for all residential and low-income customers.

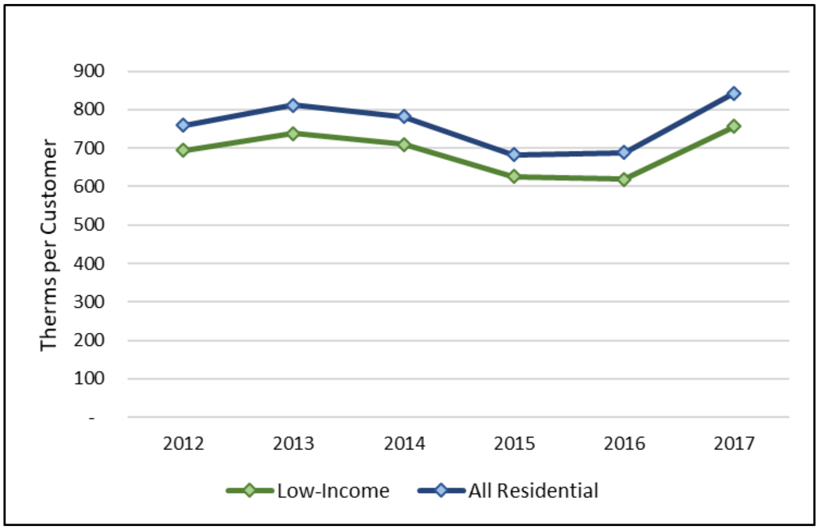


Figure 3-4. Annual Natural Gas Use per Customer, Low-Income and Average Residential

Natural gas use per low-income customer is clearly lower than the average residential customer. This is the opposite of the electric system where low-income use per customer is higher than the residential class. Natural gas low-income use per customer averaged about 10 percent lower than average residential usage between 2015 and 2017. This means that low-income natural gas customers will have a 10 percent lower exposure (lower rebates and surcharges) to the decoupling rate (Schedule 175) than the average residential customer. Possible explanations for lower use per customer in low-income residences are explored in Section 3 Part E.

Average customer revenue and decoupling revenue (Schedule 175) is shown in Table 3-4, below. As explained in Section 2, deferral rates first became effective November 1, 2016. Decoupling impacts on revenues in 2016 are small because the first decoupling tariff tracker adjustment did not become effective in rates until November 1, 2016. In 2017 Schedule 175 accounted for 3.4 percent of low-income revenue and 3.7 percent of all residential revenue. On a percentage of bill basis, there is only a minor difference between low-income and all residential.[37] However, low-income customers paid just over $25 in Schedule 175 charges in 2017, $3.55 less than all residential. This is consistent with lower use per customer of low-income customers. Natural gas low-income customers will also receive a lower rebate than all residential when Schedule 175 is negative.

[37] Natural gas low-income customers show Schedule 175 revenue to be a slightly smaller percentage of the total bill.

Table 3-4. Comparison of Average Annual Natural Gas Revenue per Customer

Customer Group	2016 Revenue	2016 Schedule 175 Revenue	2016 Percent of Bill	2017 Revenue	2017 Schedule 175 Revenue	2017 Percent of Bill
Low-Income	$ 629	$ 3.39	0.5%	$ 731	$ 25.01	3.4%
All Residential	$ 669	$ 3.99	0.6%	$ 781	$ 28.56	3.7%
Difference	$ (40)	$ (0.60)	-0.1%	$ (50)	$ (3.55)	-0.2%

Monthly natural gas usage and revenue details for the two residential groups are shown in Table 3-5 for 2016 and 2017. The data for all residential is the same as reported in Section 2, repeated here for ease of comparison to low-income customers.

Schedule 175 revenue varies with the prevailing rate and the pattern of monthly usage. Average monthly payments are show in Figure 3-5 for both residential groups.

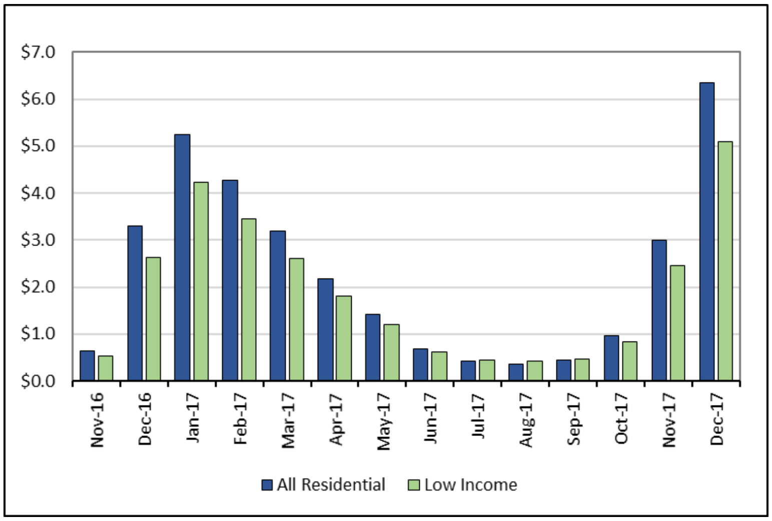


Figure 3-5. Comparison of Average Monthly Natural Gas Schedule 175 Revenue per Customer

In 2017 the average low-income customer Schedule 175 payments ranged from a low of $0.42 in August to a high of $5.09 in December with higher winter usage and the new higher Schedule 175 rate effective November 1, 2017. The impact of lower use per customer on Schedule 175 revenue is also evident in the chart with payments from low-income customers averaging $0.30 a month lower than all residential.

Table 3-5. Monthly Natural Gas, Meters and Revenue, Low-Income and All Residential

	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	TOTAL
ALL RESIDENTIAL													
Total Usage (therms)	21,914,729	16,787,450	12,859,745	9,114,929	4,269,068	3,281,704	2,537,766	2,130,642	2,604,714	4,453,518	8,310,385	17,650,621	105,915,271
Total Revenue ($)	18,879,152	15,475,562	12,055,204	8,827,648	4,825,298	4,036,778	3,447,475	3,133,744	3,526,926	5,021,986	8,073,365	15,685,499	102,988,637
Number of Meters	152,912	153,882	153,511	153,360	153,389	153,224	153,459	153,740	154,156	154,684	155,353	155,792	153,955
Avg Usage (therms)	143	109	84	59	28	21	17	14	17	29	53	113	688
Average Revenue ($)	123	101	79	58	31	26	22	20	23	32	52	101	669
Total Schedule 175 Revenue ($)	0	0	0	0	0	0	0	0	0	2	99,281	515,080	614,363
Avg Schedule 175 Revenue ($)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.64	3.31	3.99
Percent of Avg Bill	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%	3.3%	0.6%
LOW-INCOME RESIDENTIAL													
Total Usage (therms)	1,842,271	1,415,648	1,106,775	807,695	370,814	279,876	209,911	171,755	210,739	374,915	716,016	1,439,708	8,946,123
Total Revenue ($)	1,626,019	1,339,897	1,067,510	812,655	451,415	378,120	320,282	289,906	320,924	452,761	719,374	1,305,303	9,084,165
Number of Meters	15,607	15,647	15,678	15,603	15,085	14,214	12,665	11,357	12,206	14,477	15,286	15,567	14,449
Avg Usage (therms)	118	90	71	52	25	20	17	15	17	26	47	92	619
Average Revenue ($)	104	86	68	52	30	27	25	26	26	31	47	84	629
Total Schedule 175 Revenue ($)	0	0	0	0	0	0	0	0	0	0	7,997	40,987	48,985
Avg Schedule 175 Revenue ($)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.52	2.63	3.39
Percent of Avg Bill	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	0.5%

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	TOTAL
ALL RESIDENTIAL													
Total Usage (therms)	28,097,989	22,824,741	17,107,156	11,663,543	7,585,209	3,624,139	2,244,626	1,945,490	2,351,286	5,277,069	11,805,965	18,233,568	132,760,781
Total Revenue ($)	24,698,422	20,121,375	15,196,675	10,587,506	7,285,546	4,192,134	3,126,045	2,905,889	3,213,633	5,429,458	10,536,640	15,711,736	123,005,058
Number of Meters	156,425	156,620	156,919	156,785	156,510	157,170	157,080	157,589	157,973	158,697	159,255	159,738	157,563
Avg Usage (therms)	180	146	109	74	48	23	14	12	15	33	74	114	843
Average Revenue ($)	158	128	97	68	47	27	20	18	20	34	66	98	781
Total Schedule 175 Revenue ($)	822,420	668,118	500,719	341,394	222,020	106,091	65,735	56,956	68,826	154,480	478,139	1,014,478	4,499,375
Avg Schedule 175 Revenue ($)	5.26	4.27	3.19	2.18	1.42	0.68	0.42	0.36	0.44	0.97	3.00	6.35	28.56
Percent of Avg Bill	3.3%	3.3%	3.3%	3.2%	3.0%	2.5%	2.1%	2.0%	2.1%	2.8%	4.5%	6.5%	3.7%
LOW-INCOME RESIDENTIAL													
Total Usage (therms)	2,288,240	1,880,864	1,420,260	975,231	640,493	304,001	176,484	156,616	184,631	417,965	918,874	1,375,557	10,739,216
Total Revenue ($)	2,057,808	1,693,264	1,293,014	915,326	649,284	386,266	285,911	266,734	286,234	461,743	854,963	1,221,052	10,371,598
Number of Meters	15,588	15,617	15,628	15,538	15,364	14,377	11,815	10,781	11,497	14,386	14,844	14,829	14,189
Avg Usage (therms)	147	120	91	63	42	21	15	15	16	29	62	93	757
Average Revenue ($)	132	108	83	59	42	27	24	25	25	32	58	82	731
Total Schedule 175 Revenue ($)	65,845	53,942	40,741	27,997	18,489	8,833	5,225	4,512	5,329	12,021	36,409	75,490	354,833
Avg Schedule 175 Revenue ($)	4.22	3.45	2.61	1.80	1.20	0.61	0.44	0.42	0.46	0.84	2.45	5.09	25.01
Percent of Avg Bill	3.2%	3.2%	3.2%	3.1%	2.8%	2.3%	1.8%	1.7%	1.9%	2.6%	4.3%	6.2%	3.4%

Summary – Task 3, Parts A and D

The decoupling deferral tracker adjustment, Schedule 75 for electric and Schedule 175 for natural gas, has had a relatively small impact on low-income customer bills. In 2017, the first-year decoupling rates were effective the full calendar year, the average low-income customer paid $37 in Schedule 75 charges and $25 in Schedule 175 charges. These charges amounted to 2.9 percent of the average low-income electric bill and 3.4 percent of the average low-income natural gas bill. Looking forward to 2018, both Schedule 75 and Schedule 175 are expected to be negative effective November 1, 2018, resulting in a rebate from decoupling through October 2019.

On a percentage of bill basis there is no meaningful difference in decoupling charges between low-income and all residential customers. However, low-income use per customer averaged about 10 percent higher than average residential usage on the electric system and 10 percent lower on the natural gas system. This means that low-income electric customers have a 10 percent greater exposure (higher rebates and surcharges) to the decoupling rate than the average residential customer and low-income natural gas customers have a 10 percent lower exposure. Possible explanations for higher electric and lower natural gas use per customer in low-income residences are explored in Section 3 Part E.

Low-Income Savings, Expenditures and Customers Served

Task 3, Part B is defined as follows:

> "3b) A summary of annual low-income conservation program savings, expenditures and customers served compared with the rest of the residential class, where low-income conservation programs are defined as the programs currently being run under Electric Schedule 90 and Natural Gas Schedule 190."

Conservation Program Savings

Residential and low-income electric energy savings are shown in Table 3-6 and these results are partitioned into conservation (Table 3-7) and conversion of electric heat and hot water to natural gas Table 3-8.[38]

Table 3-6. Total Electric Energy Savings - Conservation and Conversions (kWh)

Sector	2014	2015	2016	2017
Residential	25,397,486	16,082,204	43,063,551	33,376,237
Low-Income	400,247	829,091	546,066	710,204
Percent Low-Income	1.6%	5.2%	1.3%	2.1%

[38] The source of information for the energy savings tables is the set of Washington DSM Annual Conservation Report & Cost-Effectiveness Analysis for each year from 2014 through 2017.

Table 3-7. I-937 Electric Conservation (kWh)

Sector	2014	2015	2016	2017
Residential	23,586,582	10,716,609	33,316,699	23,139,201
Low-Income	198,392	209,567	272,438	191,457
Percent Low-Income	0.8%	2.0%	0.8%	0.8%

Table 3-8. Electric Conversion to Natural Gas Savings (kWh)

Sector	2014	2015	2016	2017
Residential	1,810,904	5,365,595	9,766,855	10,237,036
Low-Income	201,855	619,584	273,628	518,748
Percent Low-Income	11.1%	11.5%	2.8%	5.1%

The percentage of electric energy savings due to conversions is shown in Table 3-9. In 2017 this was about 31% for residential and about 73% for low-income.

Table 3-9. Percentage Electric Savings Due to Conversions from Electric to Natural Gas

Sector	2014	2015	2016	2017
Residential	7.1%	33.4%	22.7%	30.7%
Low-Income	50.4%	74.7%	50.1%	73.0%

Residential and low-income natural gas energy savings are shown in Table 3-10.

Table 3-10. Total Natural Gas Conservation Savings (therms)

Sector	2014	2015	2016	2017
Residential	355.443	343,395	367,891	773,030
Low-Income	14,944	13,154	18,490	3,034
Low-Income as a Percentage of Other Residential	4.2%	3.8%	5.0%	0.4%

Before turning to expenditures and customers served, we first provide a discussion of the low-income payment assistance and energy savings programs.

Avista service to low-income customers includes both bill assistance and low-income weatherization programs. Bill assistance programs are analyzed first, followed by low-income weatherization.

Low-Income Bill Assistance

To assess the impact of the decoupling mechanism on Avista's low-income customers we evaluated the trends in bill assistance before and after decoupling implementation in January 2015. We analyzed each of the bill assistance programs that are available to assist Avista low-income customers including bill assistance funded by outside organizations. The purpose of these programs is to alleviate the home energy burden for low-income customers and to provide emergency assistance as required, while keeping service connected.

Low-Income Rate Assistance Program (LIRAP)

LIRAP provides energy assistance grants to low-income customers in Washington, Idaho, and Oregon. LIRAP grants are used to help with paying off a portion of a past due energy bill to ease the energy burden on limited income customers below one-hundred and twenty-six percent (126%) of the Federal Poverty Level (FPL). Benefits for limited income households are based on eligibility and a percentage of the customers' utility bill.

LIRAP services are delivered by the Washington State Department of Commerce (DOC) in collaboration with a network of Community Actions Agencies (CAA) throughout the Avista service area in Washington State. The CAA's provide the client intake and eligibility determination services required to distribute LIRAP benefits.

The program is funded by rate payers through the LIRAP Tariff Rider applied to energy usage on both electric and natural gas customers. The LIRAP tariff rate for electric service is established through the rate setting process and decided by the Washington State Utilities and Transportation Commission. The level of LIRAP funding is determined by the Schedule 92 and Schedule 192 rate applied to the volumes of electric and natural gas sales, respectively. Table 3-11 presents the electric service LIRAP tariff rates in each of the listed rate schedules used to determine the available funding.[39]

To provide a simple combined view of the overall trends in the LIRAP electric service tariff rate since 2015 we calculated a weighted average $/kWh LIRAP rate. The calculation included all schedules listed in Table 3-11 except Schedules 41-48 since these schedules are not billed on a $/kWh basis.

The weights are based on the projected dollar sales of electricity in each of the affected rate schedules listed in Table 3-11.[40] Figure 3-6 illustrates that the weighted average LIRAP rate increased steadily since 2012 and has continued that trend after 2015 and through 2017. This trend is projected to continue with a proposed increase planned for October 1, 2018.

[39] DR Response: 073, Attach. A and DR Response: 073 Attach. A, Revised

[40] DR Response: 073, Attach. A and DR Response: 073 Attach. A, Revised

Table 3-11. Electric Service LIRAP Tariff Rate

		Effective Dates								
	Schedules	**01-Jan-12**	**01-Jan-13**	**01-Jan-14**	**01-Jan-15**	**01-Oct-15**	**11-Jan-16**	**01-Oct-16**	**01-Oct-17**	**01-Oct-18**
		(dollars per kWh)								
Residential	1 and 2	0.00066	0.00068	0.00070	0.00081	0.00085	0.00091	0.00097	0.00104	0.00111
General Service	11, 12	0.00095	0.00098	0.00101	0.00117	0.00123	0.00132	0.00141	0.00151	0.00162
Large General Service	21, 22	0.00070	0.00072	0.00074	0.00085	0.00089	0.00095	0.00102	0.00109	0.00117
Extra Large General Service	25	0.00044	0.00045	0.00046	0.00053	0.00056	0.00060	0.00064	0.00068	0.00073
Pumping	30, 31, 32	0.00060	0.00062	0.00064	0.00074	0.00078	0.00083	0.00089	0.00095	0.00102
Weighted Average		**0.00067**	**0.00070**	**0.00072**	**0.00085**	**0.00090**	**0.00096**	**0.00103**	**0.00110**	**0.00118**
		(percent of base rates)								
Street & Area Lighting	41-48	0.85%	0.88%	0.88%	0.99%	1.04%	1.13%	1.21%	1.29%	1.38%

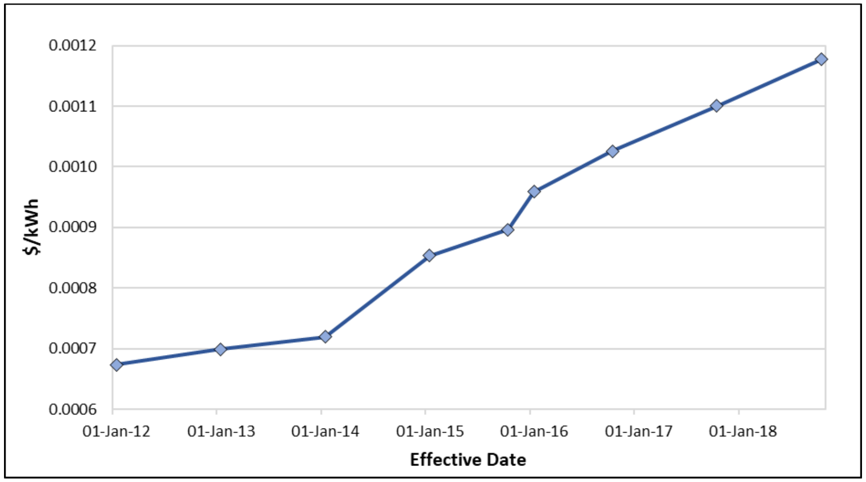


Figure 3-6. Electric Service LIRAP Tariff (Weighted Average)

Table 3-12 presents the natural gas service LIRAP tariff rate which is applied to therms of natural gas sales for each of the rate schedules listed to determine available funding. The LIRAP natural gas rate is established through the rate setting process and decided by the Washington State Utilities and Transportation Commission.

To provide a simple combined view of the overall trends in the LIRAP natural gas service tariff rate since 2012, we calculated a weighted average LIRAP rate for all affected rate schedules. The weights are based on the projected dollar sales of natural gas in each of the affected rate schedules listed in Table 3-12.

Figure 3-7 shows that the weighted average natural gas LIRAP tariff rate increased steadily since 2012 through 2017. The positive trend is expected to continue with a proposed increase in the natural gas service LIRAP tariff rate planned for October 1, 2018.

Table 3-12. Natural Gas Service LIRAP Tariff Rate

	Schedules	Effective Dates ($/therm)								
		01-Jan-12	**01-Jan-13**	**01-Jan-14**	**01-Jan-15**	**01-Oct-15**	**11-Jan-16**	**01-Oct-16**	**01-Oct-17**	**01-Oct-18**
General Service	101, 102	0.01094	0.01134	0.01145	0.01410	0.01478	0.01712	0.01832	0.01910	0.02044
Large General Service	111, 112	0.00917	0.00951	0.00960	0.01182	0.01239	0.01435	0.01535	0.01600	0.01712
Extra Large General Service	121, 122	0.00837	0.00868	0.00876	0.01079	0.01131	0.01310	0.01402	0.01462	0.01564
Interruptible	131, 132	0.00804	0.00834	0.00842	0.01037	0.01087	0.01259	0.01347	0.01404	0.01502
Transportation	146					0.00084	0.00097	0.00104	0.00083	0.00083
Weighted Average		**0.01043**	**0.01082**	**0.01093**	**0.01344**	**0.01396**	**0.01617**	**0.01730**	**0.01805**	**0.01933**

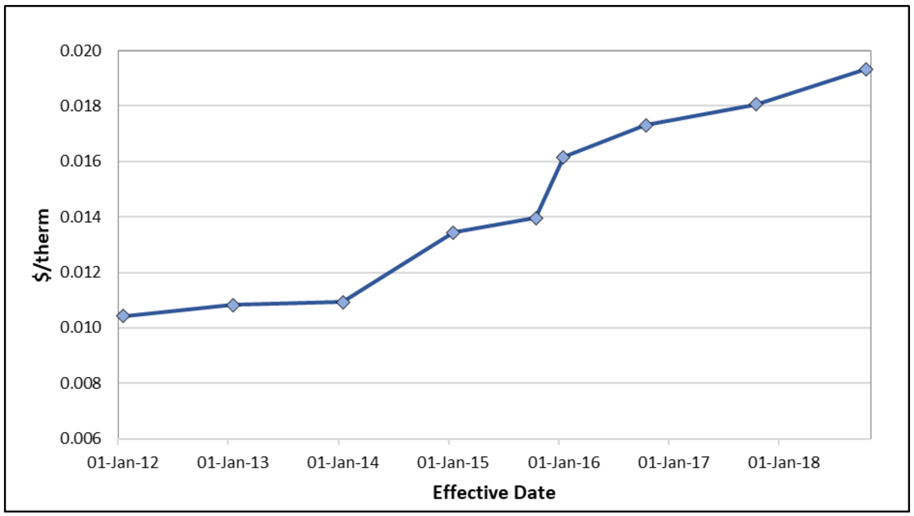


Figure 3-7. Natural Gas Service LIRAP Tariff (Weighted Average)

Rate Discount Pilot Program for Seniors

Avista has an experimental pilot program that offers a rate discount to fixed-income seniors and customers with disabilities whose household income is between one-hundred and twenty-six percent (126%) and two-hundred percent (200%) of the FPL. This program began October 1, 2015 and will end September 30, 2019, though it continues for those customers who are currently enrolled. The rate discount is limited to 800 customers (700 in Spokane County and 100 in Stevens, Lincoln and Ferry counties. The pilot program was only available through SNAP and Rural Resources for customers in Spokane, Stevens, Lincoln and Ferry counties. This program is an innovative approach for Avista and was implemented in the year that decoupling started.[41]

Low-Income Home Energy Assistance Program (LIHEAP)

LIHEAP is funded by the US Department of Health and Human Services (HHS). It operates in every state and the District of Columbia, as well as on most tribal reservations and U.S. territories. The purpose of LIHEAP is to assist low-income households, particularly those with the lowest incomes who pay a high proportion of household income for home energy, primarily in meeting their immediate home heating and cooling needs. The primary factor determining eligibility is the household income level which must be at or below the LIHEAP State Poverty Guideline (Table 3-13).

Table 3-13. LIHEAP Poverty Guidelines (2017)

Number of Persons in Household	State Poverty Guideline for LIHEAP	Number of Persons in Household	State Poverty Guideline for LIHEAP
1	$12,060	5	$28,780
2	$16,240	6	$32,960
3	$20,420	7	$37,140
4	$24,600	8	$41,320

The LIHEAP statute defines home energy as a source of heating or cooling in residential dwellings. The LIHEAP block grant serving Avista customers is administered by the Washington State Department of Commerce (DOC) in collaboration with a network of CAAs' across the state.

Because LIHEAP is a Block Grant program, states are authorized to add additional criteria to determine the level of benefit provided to each eligible household such as hypothermia risk, crisis interventions, and high energy burden.

Project Share

Project Share[42] is a donation-based program that helps keep homes warm through crisis situations like a sudden loss of income, expensive medical costs, malfunctioning heating equipment and other unforeseen circumstances that deplete available funds and make it difficult to pay household energy costs. The program is a partnership between utilities, fuel vendors and

[41] Cornwell, John, Avista Low-income Rate Assistance Program Rate Discount Pilot Impact and Process Evaluation, Primary Report Update. Evergreen Economics: July 11, 2017.
[42] Response to DR 045

community action agencies that provide emergency energy assistance to qualified households that have exhausted all other energy assistance resources.

The goal of Project Share is to help stabilize households-in-crisis for 30 days. People do not need to meet federal poverty guidelines to qualify, but they must contact their energy provider to make payment arrangements to avoid future emergencies.

- Project Share funds can help cover utility bills, deposits, deliverables – oil, wood, coal or propane – and furnace repairs.
- Project Share decisions are made on a case-by-case basis in accordance with the Project Share Administration and Distribution of Funds Agreement.

Project Share currently receives donations from[43]:

- The Avista Corporation
- Avista employees
- Avista customers
- Ferry County PUD customers
- Inland Power & Light Corporation
- Inland Power & Light customers
- Modern Electric customers
- The Spokane AdFed Golf Tournament

Miscellaneous Bill Assistance

The MISC[44] Assistance Category consists of several dozen organizations that provide energy assistance grants to Avista customers. These organizations include churches, social service and government agencies: such as the Salvation Army, Catholic Charities, the Department of Health and Human Services or the local Housing Authority. Energy Assistance is not the primary way that these organizations help individuals (it is not their core mission or function); however, during their service they may help individuals with their utility bill. Additionally, many of these organizations do not have an established source for funding to help with energy assistance. In receiving these assistance payments Avista customers are categorized as MISC within the Customer Care and Billing System.

[43] Funds raised from Utilities other than Avista provide bill assistance benefits to customers of those utilities and not to Avista customers.
[44] Response to DR 046.

Bill Assistance Funding Trends

The bill assistance funding study period (2012-2017) provides three years of pre-decoupling data and three years of post-decoupling data. Figure 3-8 illustrates that between 2012 and 2014, combined bill assistance funding levels from all sources were stable ranging between $8.26 and $8.83 million per year.[45] In 2015 a significant decrease in funding was reported, from $8.7 in 2014 to $6.8 million in 2015.

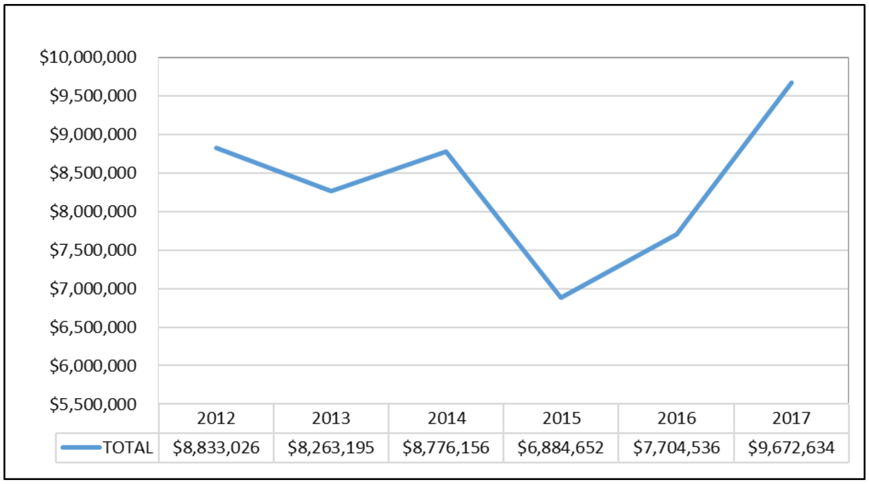


Figure 3-8. Value of All Bill Assistance Grants

Figure 3-9 illustrates that funding levels for all of the four bill assistance programs decreased in 2015. The largest declines were the LIHEAP and MISC sources. Overall funding levels recovered in both 2016 and 2017; however, the recovery was not uniform for each funding source.

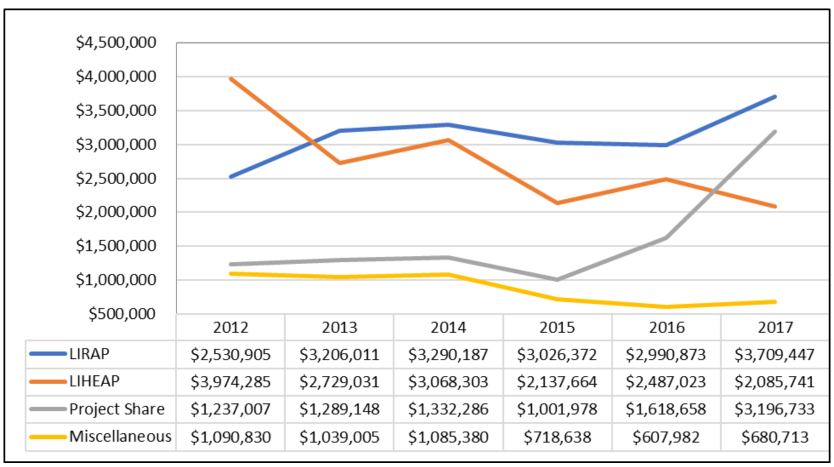


Figure 3-9. Value of Bill Assistance by Funding Source

Since 2015 the LIHEAP funding trend has been level while LIHEAP and MISC funding continued to slightly decline. However, LIRAP and Project Share both show significant increases

[45] DR Responses: 026 Attach. A, 027 Attach. A, 028 Attach. A, 048 Attach. A, 048 Attach. B

in funding levels, particularly Project Share which increased funding by $2,194,755 between 2015 and 2017. Project Share and LIRAP funding have made up for losses from LIHEAP and MISC funding reductions over the study period. Figure 3-9 reflects a shift in bill assistance funding with increased dependence on LIRAP and Project Share and reduced dependence on LIHEAP and MISC. This reflects a shift toward increased local and utility funding. LIHEAP funding like other federal block grants is subject to significant changes depending on Congressional Appropriations.

Number of Bill Assistance Grants

Figure 3-10 shows a significant decrease in the combined number of grants from all funding sources provided in 2015, reflecting the decreased funding levels for each funding source in 2015. [46] This is followed by a recovery in the number of grants in 2016 and 2017.

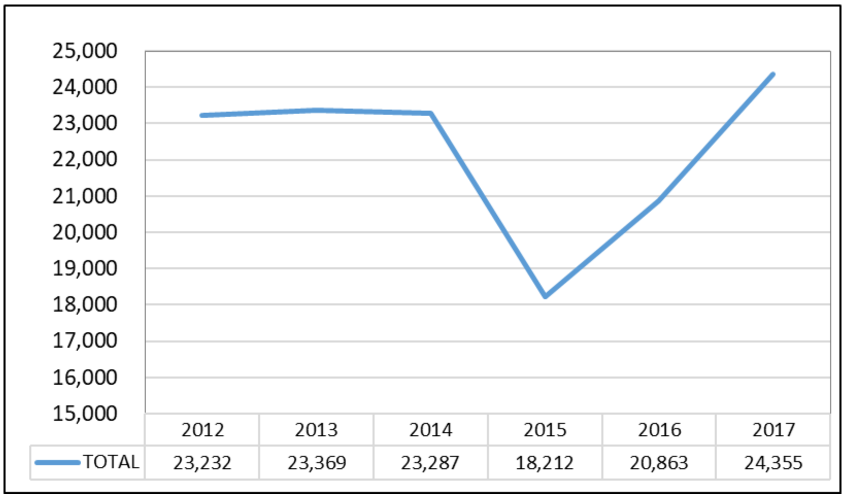
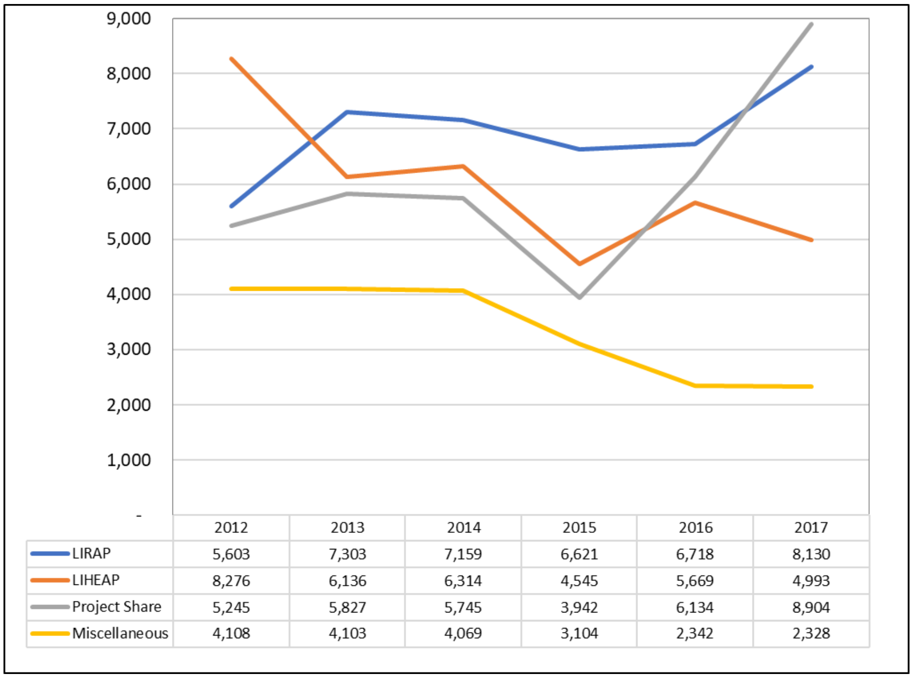


Figure 3-10. Number of Bill Assistance Grants Provided

Figure 3-11 illustrates the trend in the number of bill assistance grants for each funding source.[47] The data reflects a continuing downward trend in the number of MISC bill assistance grants and a leveling-off of the number on LIHEAP bill assistance grants. Consistency with funding levels, the numbers of LIRAP and Project Share grants has increased annually since 2015 and has made up for the decreases in the LIHEAP and MISC bill assistance grants provided to Avista customers.

[46] Responses to DRs: 021 Attach. A, 021 Attach. B, 021 Attach. C, 022 Attach. A, 023 Attach. A, 024 Attach. A, 047 Attach. A.

[47] Response to DR's: 021 Attach. A, 021 Attach. B, 021 Attach. C, 022 Attach. A, 023 Attach. A, 024 Attach. A, 047 Attach. A, 026 Attach. A, 027 Attach. A, 028 Attach. A, 048 Attach. A, 048 Attach. B.



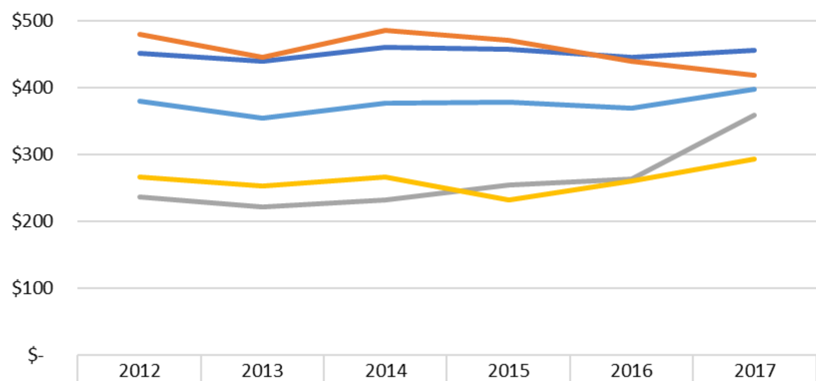
	2012	2013	2014	2015	2016	2017
LIRAP	5,603	7,303	7,159	6,621	6,718	8,130
LIHEAP	8,276	6,136	6,314	4,545	5,669	4,993
Project Share	5,245	5,827	5,745	3,942	6,134	8,904
Miscellaneous	4,108	4,103	4,069	3,104	2,342	2,328

Figure 3-11. Number of Bill Assistance Grants by Funding Source

Average Bill Assistance Grant

Figure 3-12 presents the average grant levels of the bill assistance grants for each of the funding sources. [48] The average grant levels have remained relatively stable over the (2012-2017) evaluation period with a modest increase from $378 in 2015 to $397 in 2017.

[48] Response to DR's: 021 Attach. A, 021 Attach. B, 021 Attach. C, 022 Attach. A, 023 Attach. A, 024 Attach. A, 047 Attach. A, 026 Attach. A, 027 Attach. A, 028 Attach. A, 048 Attach. A, 048 Attach. B.



	2012	2013	2014	2015	2016	2017
LIRAP	$452	$439	$460	$457	$445	$456
LIHEAP	$480	$445	$486	$470	$439	$418
Project Share	$236	$221	$232	$254	$264	$359
Miscellaneous	$266	$253	$267	$232	$260	$292
Total Average	$380	$354	$377	$378	$369	$397

Figure 3-12. Average Bill Assistance Grant by Funding Source

Low-Income Weatherization Services

Avista provides low-income customers with weatherization rebates to reduce costs of energy with the following qualifying conditions.[49]

- Primary fuel used for space heating must be Avista electric or natural gas service.
- Rebates must be submitted within a year of completion of energy efficiency measure,
- Only new equipment qualifies.
- All improvements must be agency or contractor installed.
- The rebates are available for primary residential single family up to a fourplex, including manufactured and modular homes.
- Rebates are not available for seasonal or recreational homes or condos.

Low-income weatherization rebates fund such measures as air sealing, attic insulation, wall insulation, duct sealing, and conversion from electric space heating and hot water to natural gas space heating and hot water. The community action agencies select the clients and determine the optimal measures for each home.

LIHEAP weatherization dollars and US Department of Energy Weatherization Assistance Program (WAP) also fund weatherization services in homes of Avista low-income customers. However, the Company only tracks low-income weatherization work that is funded through the Avista Demand Side Management (DSM) Tariff Rider.

[49] Avista Website: Rebates: Washington - Avista

Avista Low-Income Weatherization Funding

Avista's low-income home weatherization program is funded strictly through the company's DSM Tariff Rider. The DSM tariff rate for electric service is established through the rate setting process and decided by the Washington State Utilities and Transportation Commission. Table 3-14 presents the electric service DSM tariff rates which are applied to kWh sales in each of the listed rate schedules to determine the available funding.[50]

Table 3-14. Electric Service DSM Tariff

		Effective Dates ($/kWh)						
	Schedules	**01-Aug-12**	**01-Aug-13**	**01-Aug-15**	**08-Apr-16**	**01-Aug-16**	**01-Aug-17**	**01-Sep-18**
Residential	1, 2	0.00168	0.00268	0.00215	0.00201	0.00262	0.00344	0.00433
General Service	11, 12	0.00235	0.00365	0.00289	0.00272	0.00362	0.00463	0.00597
Large General Service	21, 22	0.00176	0.00276	0.00220	0.00208	0.00273	0.00366	0.00460
Extra Large General Service	25	0.00111	0.00176	0.00137	0.00129	0.00172	0.00232	0.00297
Pumping	30, 31, 32	0.00155	0.00245	0.00198	0.00190	0.00261	0.00341	0.00433
Street & Area Lighting	41-48	0.02030	0.03130	0.02400	0.02360	0.00862	0.01215	0.02017
Weighted Average		**0.00197**	**0.00311**	**0.00247**	**0.00234**	**0.00276**	**0.00364**	**0.00469**

To provide a simple combined view of the overall trends in the electric service DSM tariff rate since 2015, we calculated a weighted average electric service DSM tariff rate for all affected rate schedules. The weights are based on the projected dollar sales of natural gas in each of the affected rate schedules listed in Table 3-14. Figure 3-13 illustrates the weighted average electric service DSM tariff rate from 2012 to 2018.[51] After increasing in 2013 the weighted average decreased until an increase in August 2016. It increased again in 2017 and is projected to increase in September of 2018.

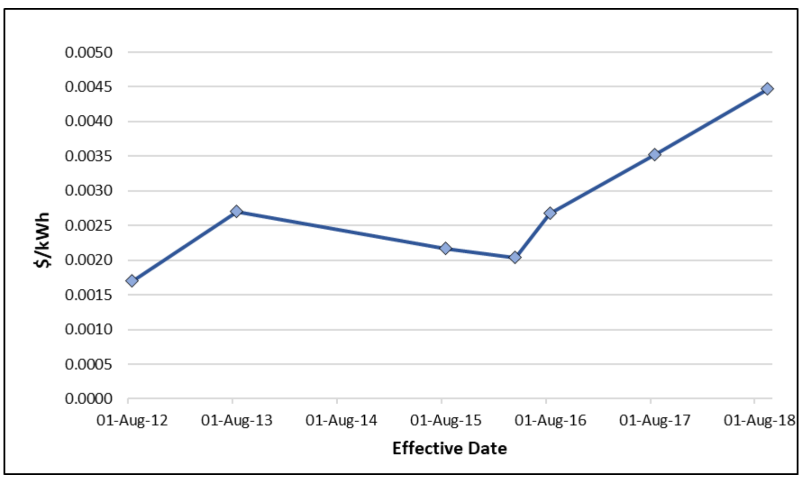


Figure 3-13. Electric Service DSM Tariff (Weighted Average)

Table 3-15 presents the effective DSM natural gas tariffs for each customer class from August 1, 2012 to September 1, 2018.[52] The DSM natural gas tariff rates are applied to Therm of natural

[50] Response to DR 074 Attach. Revised
[51] Response to DR 074 Attach. Revised
[52] Ibid.

gas sales in each of the listed rate schedules determine the available funding for DSM services. The DSM tariff rate for natural gas service is established through the rate setting process and decided by the Washington State Utilities and Transportation Commission.

Table 3-15. Natural Gas Service DSM Tariff

		Effective Dates ($/therm)				
	Schedules	**01-Aug-12**	**01-Nov-15**	**01-Jul-16**	**01-Jun-17**	**01-Sep-18**
General Service	101, 102	0.02310	0.02750	0.03472	0.02229	0.03028
Large General Service	111, 112	0.01824	0.02095	0.02475	0.01581	0.01626
Extra Large General Service	121, 122	0.01630	0.01965	0.02176	0.01614	0.01276
Interruptible	131, 132	0.01476	0.02384	0.02300	0.01521	0.01132
Weighted Average		**0.02177**	**0.02578**	**0.03220**	**0.02071**	**0.02745**

To provide a simple combined view of the overall trends in the DSM natural gas service tariff rate since 2015, we calculated a weighted average for all affected rate schedules. The weights are based on the projected dollar sales of natural gas in each of the affected rate schedules listed in Table 3-14.

Figure 3-14 illustrates the trend in the weighted average DSM natural gas tariff from August 1, 2012 to September 1, 2018.[53] The weighted average tariff increased from August 2012 through July 2016. It decreased in July 2017, and it is projected to be increased in September 2018. However, the weighted average projected DSM natural gas tariff rate, effective September 2018, is lower than the July 2016 rate.

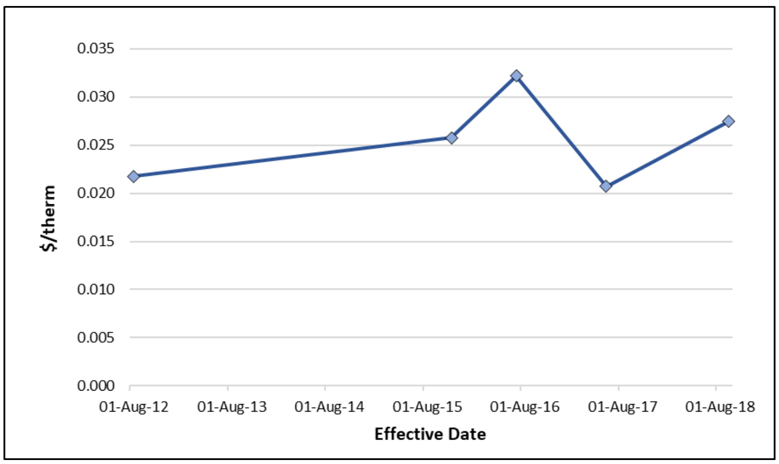


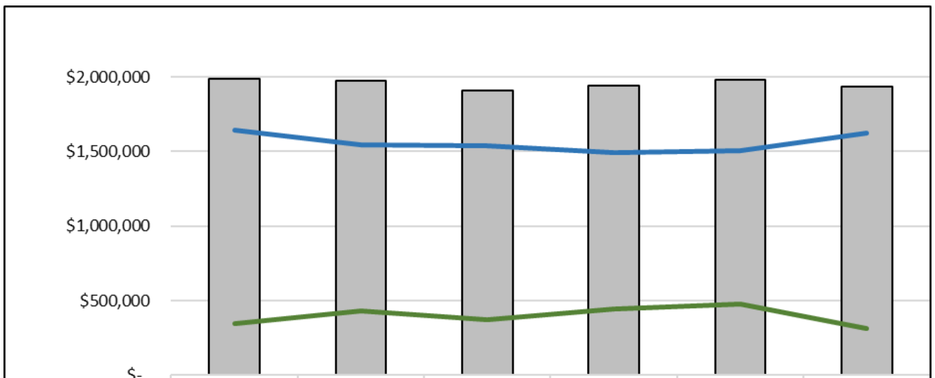
Figure 3-14. Natural Gas Service DSM Tariff (Weighted Average)

[53] Ibid.

Low-income weatherization is funded as follows:

> "Avista is ordered through General Rate Case settlements to spend tariff rider funds on low-income weatherization. Since 2012, $2 million is set aside for Washington customers who meet the income qualification requirements. This has been allocated to six network agencies and since 2015 also includes a tribal housing authority. The division of $2 million is done by determining the meter count in each county the agencies serve. The percentage of meters is then applied to the $2 million to create an allocation by agency for weatherization and other energy efficiency improvements for the income qualified home." [54]

Figure 3-15 presents overall funding trends and separates funding levels for electric and natural gas customers.[55, 56] Since 2015 the weatherization allocation to electric customers decreased from 23% to 16% while the allocation to natural gas customers increased from 77% to 84% of the total allocation. Overall funding allocations have remained stable.



	2012	2013	2014	2015	2016	2017
Total	$1,989,852	$1,974,533	$1,909,936	$1,939,835	$1,983,215	$1,937,085
Electric	$343,833	$429,520	$370,496	$446,208	$474,472	$312,831
Natural Gas	$1,646,019	$1,545,013	$1,539,440	$1,493,627	$1,508,743	$1,624,254

Figure 3-15. Avista Low-Income Weatherization Funding Trends

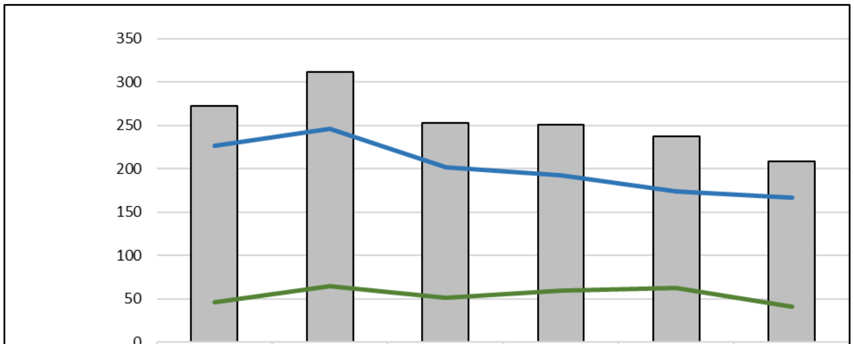
54 Response to DR 075.

55 For the purpose of this analysis the electric category includes electric-only customers while the natural gas category includes both natural gas-only customers and dual-service (natural gas and electric) customers.

56 Responses to DR's: 033 Attach. A, 034 Attach. A, 035 Attach. A, 036 Attach. A

Number of Low-Income Weatherization Grants

Figure 3-16 illustrates that the number of Avista low-income weatherization jobs increased from 2012 to 2013 when it reached its highest level during the study period.[57] The trend in the number of low-income weatherization grants then began a downward trend from 2013 through 2017. The decrease in the number of grants reflects the increasing average cost of the weatherization jobs.

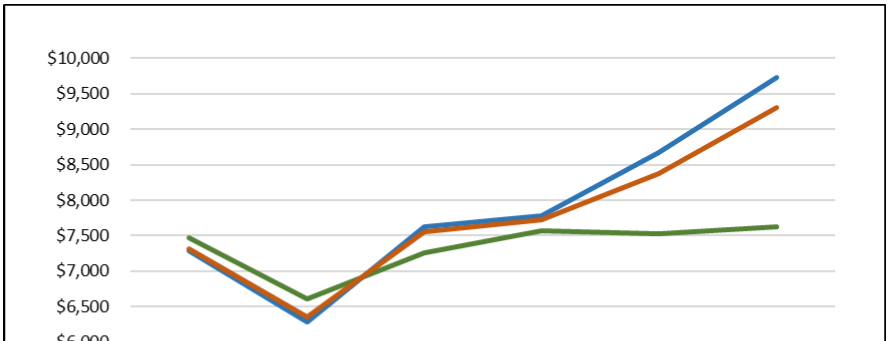


	2012	2013	2014	2015	2016	2017
Total	272	311	253	251	237	208
Electric	46	65	51	59	63	41
Natural Gas	226	246	202	192	174	167

Figure 3-16. Number of Low-Income Weatherization Grants

Average Weatherization Job Costs

Figure 3-17 presents the average cost of low-income weatherization jobs for electric and natural gas customers.[58] While the average cost of both electric customer and natural gas customer jobs have increased consistently since 2013, the cost of natural gas jobs has increased at a faster rate.



	2012	2013	2014	2015	2016	2017
Electric	$7,475	$6,608	$7,265	$7,563	$7,531	$7,630
Natural Gas	$7,283	$6,281	$7,621	$7,779	$8,671	$9,726
Average	$7,316	$6,349	$7,549	$7,728	$8,368	$9,313

Electric Natural Gas Average

Figure 3-17. Average Cost of Weatherization Jobs

[57] Ibid.

[58] Responses to DR's: 029 Attach. A, 030 Attach. A, 031, 032 Attach. A, 033 Attach. A, 034 Attach. A, 035 Attach. A, 036 Attach. A, 049 Attach. A

Inflation Adjusted Funding Levels

To account for the cost of living increases since 2012, we calculated inflation adjusted funding levels for both low-income bill assistance and low-income weatherization programs.

Figure 3-18 presents inflation adjusted bill assistance funding levels for Avista customers from all funding sources including LIRAP, LIHEAP, Project Share and MISC using the Bureau of Labor Statistics Inflation Adjustment Calculator.[59] The inflation adjusted data reflects the buying power of the funding based on the 2012-dollar value. The inflation adjusted curve in Figure 15 represents the trend in the buying power value of bill assistance over the evaluation period. Inflation adjusted bill assistance funding has increased since 2015 and 2017 levels and are above 2012 funding.

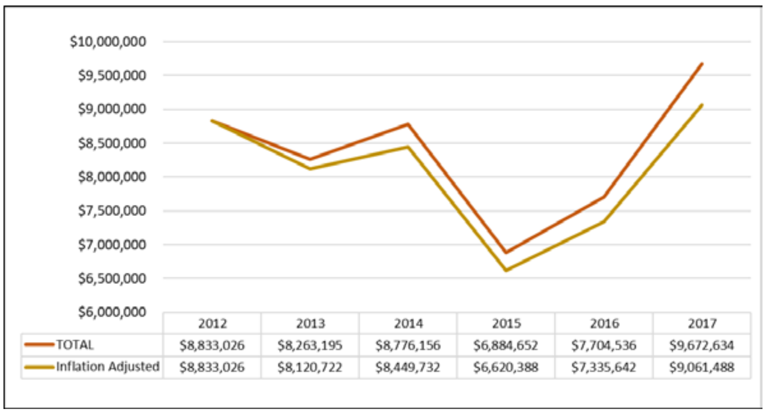


Figure 3-18. Inflation Adjusted Bill Assistance (All Sources)

Figure 3-19 presents inflation adjusted Avista low-income weatherization funding levels, using the Bureau of Labor Statistics Inflation Adjustment Calculator. Inflation adjusted Avista weatherization funding has decreased from 2012 to 2015 and continued to decrease through 2017.

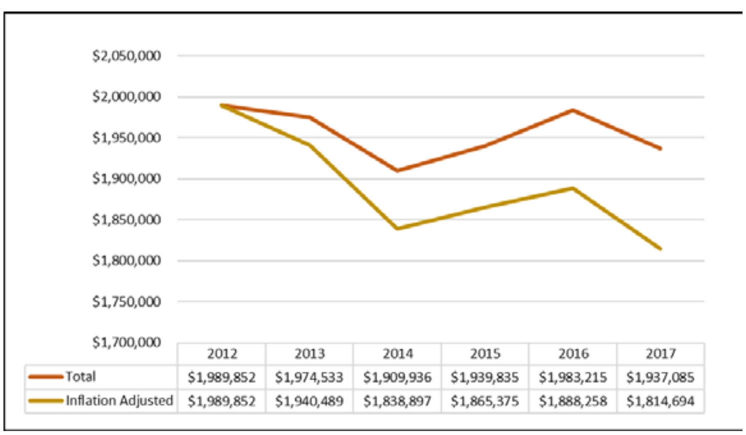


Figure 3-19. Inflation Adjusted Avista Weatherization Funding

[59] https://www.bls.gov/data/inflation_calculator.htm

Summary – Task 3, Part B

Avista low-income customers are provided with bill assistance and weatherization services funded by Avista and several other Federal, State, and community-based organizations. These services are provided in cooperation with the Washington State Department of Commerce, the Community Action Agency network across the State, the LIHEAP program, Project Share and directly through community-based groups.

We have provided an overview of all the bill assistance programs available to Avista customer from all funding sources. Since Decoupling was implemented in 2015 the level of bill assistance funding has increased. The increase in funding was driven by the Avista LIRAP program and the Project Share program each of which showed significant increases while LIHEAP funding remained level and MISC funding declined. Because of the increases in LIRAP and Project Share funding the number of customers receiving bill assistance increased from 18,212 to 24,355 households. During the same period average bill assistance benefits increased from $378 to $397 per grant.

While Avista customers receive weatherization services from several sources, only Avista weatherization is tracked by the Company and is analyzed in this evaluation. Avista weatherization funding remained level at approximately $2 million per year between 2012 and 2017. Inflation adjusted Avista weatherization funding decreased from 2012 to 2015 and continued to decrease through 2017.

During the 2015 to 2017 period the average Avista weatherization costs increased from $7,728 to $9,313 per customer. Because of increasing costs and level funding, the number of weatherization rebates decreased. Since decoupling was implemented in 2015, the number of weatherization rebates decreased from 251 to 208.

This analysis did not evaluate whether the low-income energy assistance programs reviewed in this report are adequate to meet the need. The RFP No. R -41321 provided two Attachments that address this question: *Attachment G - An Estimate of the Number of Households in Poverty Served by Avista Utilities in Washington State*[60] and Attachment H - *The Self-Sufficiency Standard for Washington State 2014*.61 We have analyzed these reports and have provided our findings in Section 8 (Low-Income Appendix) of this evaluation.

[60] *An Estimate of the Number of Households in Poverty Served by Avista Utilities in Washington State*, Brian Kennedy, MS and D. Patrick Jones, Ph.D., Institute for Public Policy and Economic Analysis, May 2015.
[61] *The Self-Sufficiency Standard for Washington State 2014*, Diana M. Pearce, PhD, Center for Women's Welfare and the School of Social Work at the University of Washington, Revised August 2015.

Modifications to Low-Income Programs

Task 3, Part C is defined as follows:

> "(3c) A description of any modifications to conservation programs targeted to low-income customers since the inception of the Mechanisms including changes to funding levels as well as changes to specific measures."

The funding level for conservation programs targeted to low-income customers since the inception of the Mechanisms in 2015 is best reflected in Figure 3-19, for which the relevant portion is from 2015 onwards. As shown in this figure, Avista inflation-adjusted Weatherization funding increased from 2015 to 2016 and then dropped in 2017. The unadjusted amounts were $1,939,835 in 2015, $1,983,215 in 2016 and $1,937,085 in 2017, or essentially, about $2,000,000 per year. The adjusted amounts were $1,865,375 in 2015, $1,888,258 in 2016 and $1,814,694 in 2017, or roughly from about $1,900,000 to $1,800,000 per year in real dollars. From an administrative perspective, funding was essentially constant at $2,000,000 per year. In real terms, funding dropped to about $1,800,000 in 2017. This suggests that Avista might want to take inflation into account in carrying out the "carve out" for low-income in each year.

In 2015, the Company continued to reimburse Community Action Agencies for 100% of the cost of installation for a select group of pre-approved energy-efficiency measures (Table 3-16). The Company continued to offer an additional "Rebate List" of other energy efficiency measures (Table 3-17). Payment for measures on the "Rebate List" covers only the energy value of the measures. In this way, the CAAs are able to reliably secure funding for pre-approved measures and to leverage utility funds for partial funding of other measures that improve functionality of weatherization retrofits. Agencies can apply funds to electric or natural gas homes at their discretion and to charge a fifteen percent (15%) administration fee.

For 2016, the same system was continued, but with some changes in the measure tables. The 2016 group of pre-approved energy-efficiency measures is shown in Table 3-18. Partial rebate measures are shown in Table 3-19.

For 2017, the basic system was continued with changes in the measure tables. The 2017 group of pre-approved energy-efficiency measures is shown in Table 3-20. Partial rebate measures are shown in Table 3-21. There was also a clarification that measures found in Washington's Weatherization Manual priority list are deemed to be cost-effective and are paid at 100%, regardless of whether their computed Total Resource Cost (TRC) test value is below 1.0. Also, Health and Safety dollars may be used to fully fund measures on the partial rebate list, at the discretion of the CAAs.[62]

[62] Low-Income program changes are sourced from the Washington DSM Annual Conservation Report & Cost Effectiveness Analysis studies for 2015, 2016 and 2017.

Table 3-16. Low-Income 100% Approved Measures (2015)

Electric Measures	Natural Gas Measures
• Air infiltration • Insulation (floor, ceiling, wall) • Duct sealing • ENERGY STAR doors • Electric to Natural Gas Conversion (Space and Water Heat) • ENERGY STAR Refrigerators	• Insulation (Wall, Ceiling, and Floor) • Air infiltration • Duct sealing • ENERGY STAR doors • ENERGY STAR windows

Table 3-17. Low-Income Partial Rebate Measures (2015)

Electric Measures	Natural Gas Measures
• Duct insulation • ENERGY STAR refrigerators (for replacement of a refrigerator that is not fully operational) • High efficient water heater • Electric to air source heat pump • Electric to natural gas water heater • ENERGY STAR windows	• Duct insulation • High efficiency furnace • High efficiency water heater

Table 3-18. Low-Income 100% Approved Measures (2016)

Electric Measures	Natural Gas Measures
• Air infiltration • Duct sealing • ENERGY STAR doors • ENERGY STAR windows • High efficiency air source heat pump (8 HSPF) • Electric to air source heat pump • Insulation for attic, walls, floors, and ducts	• Air infiltration • Duct sealing • ENERGY STAR doors • ENERGY STAR windows • High efficiency furnace (90% AFUE) • Insulation for attic, walls, floors, and ducts **Fuel Conversion Measures** • Electric to natural gas furnace • Electric to natural gas furnace and water heat

Table 3-19. Low-Income Partial Rebate Measures (2016)

Electric Measures	Natural Gas Measures
• High efficiency water heaters (0.93 EF) • ENERGY STAR refrigerators • Ductless Heat Pumps	• High efficiency water heaters (0.62 EF) **Fuel Conversion Measures** • Electric to natural gas water heater

Table 3-20. Low-Income 100% Approved Measures (2017)

Electric Measures	Natural Gas Measures
• Air infiltration • Duct sealing • Insulation for attic, walls, floors, and ducts • LED lighting	• Air infiltration • Duct sealing • ENERGY STAR doors • ENERGY STAR windows • High efficiency furnace (90% AFUE) • High efficiency gas water heater • Insulation for attic, walls, floors, and ducts **Fuel Conversion Measures** • Electric to natural gas furnace • Electric to natural gas water heat • Electric to ductless heat pump

Table 3-21. Low-Income Partial Rebate Measures (2017)

Electric Measures	Natural Gas Measures
• Heat pump water heaters • ENERGY STAR refrigerators • ENERGY STAR doors • ENERGY STAR windows • Electric to air source heat pump	

Effect on Low-Income vs. Average Residential

Task 3, Parts A and D are combined and are presented in Part A, above.

Other Factors

In this section we examine additional contrast between low-income customers and other residential customers using premise specific data for nearly 130 thousand Avista residential customers in Spokane County.

The objective of Task 3 Part E, as stated in the request for proposal, is shown below:

> *"To the extent data is available, Consultant should evaluate other factors such as household size, housing stock (e.g. mobile home, multifamily) and heat source (e.g., electric space heat) and the effect of seasonality when comparing the impact of decoupling on low-income customers versus other customer groups (such as average residential customers)."*

There were no specific evaluation questions related to this objective in the RFP.

Our team approached this task by first exploring the possibility of obtaining housing attribute data such as size and vintage of construction directly from Avista or from secondary sources such as the US Census. Avista does not maintain housing attribute data within their customer information system. We also explored using the American Community Survey (Census) and American Housing Survey (HUD) but found the data details did not provide the ability to drill down and compare households by income levels, energy usage and housing attributes at the same time.

We turned next to the possibility of acquiring detailed housing attribute data directly from the Spokane County Assessor office and merging the data with Avista's customer information. After some initial testing to see what data could be acquired and a subjective assessment of data quality, we decided to pursue the development of a site-specific data base combining Avista's billing data and low-income status information with Spokane County's assessor data. The resulting data base of nearly 130 thousand Avista customers in Spokane County provides the ability to drill down in ways that would not otherwise be possible to compare housing size, type, vintage and energy intensity between low-income and other residential customers.

Overview of Approach

The approach of combining Avista residential billing records with assessor data was selected to overcome the lack of housing attribute data. Our team has had extensive experience combining county assessor data with utility data and we understand the rich analytical database that results from this effort. The resulting database is expected to provide a level of understanding and insights into contrasts between low-income and other residential customers that would not otherwise be possible in this evaluation.

Because of the time requirements involved with processing county assessor data and the fact that data structure, format and processes vary greatly between counties, we focused our effort exclusively on Spokane county which accounts for about 75 percent of all households within

Avista's Washington service territory. From the assessor data we compiled parcel-level housing attributes, including square footage, year built, number of bedrooms, heating and cooling method, housing type, and market value. From this data, we also inferred certain variables as follows:

- Owner occupancy was assigned by comparing the physical address of the parcel with the mailing address of the owner. The overall results compare favorably with Census estimates for the County.
- When possible, heating fuel was assigned based on the heating method.

Accuracy of assessor data tends to be highest for variables such as square footage of the structure, number of bedrooms and year built. Variables related to heating and cooling equipment tend to be less accurate and are often unavailable for a parcel.

To combine the county data with Avista data, we first summarized Avista's billing records to an individual premise level using standardized addresses. Low-income premises are flagged and the type of Avista service assigned as electric only, natural gas only or both. A low-income premise flag is assigned based on the existence of the premise in customer data of participants in one of Avista's low-income programs[63]. Site address is the information in common between the Avista records and assessor records. In order to increase the quality of the join, we first address standardized the two datasets using AccuMail software.[64] The datasets are address standardized, so an address-component-based match key can be used to join the Avista billing records with the Spokane county assessor data. There are limitations to joining utility records with assessor data in this manner, but the approach is highly accurate for single family housing. It tends to break down in instances where there is not a one-to-one correspondence between a utility premise record and a tax parcel record such as multifamily housing (one parcel and many utility customers).

A match key must be present in both the Avista data and the county assessor data for a premise to be retained for this analysis. Table 3-22 shows premise counts by residential group and service type that passed the match criteria.

[63] See Section 3a for more information.
[64] AccuMail is certified by the US Postal Service for address standardization and processing. Address standardization helps to improve match results. If addresses are incorrectly spelled, or components (eg, zip plus 4, pre- and post-directionals and/or city) are missing, or unit numbers are in the wrong position, the match routine will be less reliable.

Table 3-22. Avista Customer Counts by Residential Group and Service Type

Avista Service Type	Residential	Low-Income	Total	Low-Income Percent	Service Type Percent
Electric Only	14,373	4,150	18,523	22%	14%
Gas Only	14,527	892	15,419	6%	12%
Electric and Gas	81,115	14,876	95,991	16%	74%
Total	**110,015**	**19,918**	**129,933**	**15%**	**100%**

The merge results in nearly 130,000 Avista premises matched to Spokane assessor data, of which 15 percent are classified as low-income. Nearly three-fourths of the premises receive their electric and natural gas service from Avista. The remainder of this section compares housing attributes and energy usage between the two residential groups; low-income and other residential. For ease of discussion in the remainder of this section, we use the term “residential” to mean all other residential customers not identified as low-income.

Energy Usage

Annual energy usage for 2017 is shown in Figure 3-20.

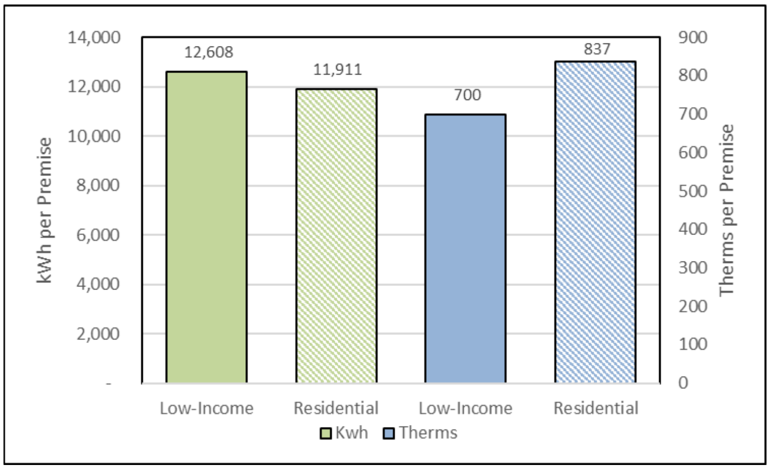


Figure 3-20. Annual 2017 Unadjusted Billed Energy Usage per Premise

Annual kWh usage for low-income premises was about 6 percent higher than residential premises in 2017. For natural gas the opposite is true with low-income premises using about 16 percent less therms over the year than residential. As will be shown below, low-income premises are smaller on average than residential. Figure 3-21 shows energy usage per square foot for both kWh and therms between the two groups.

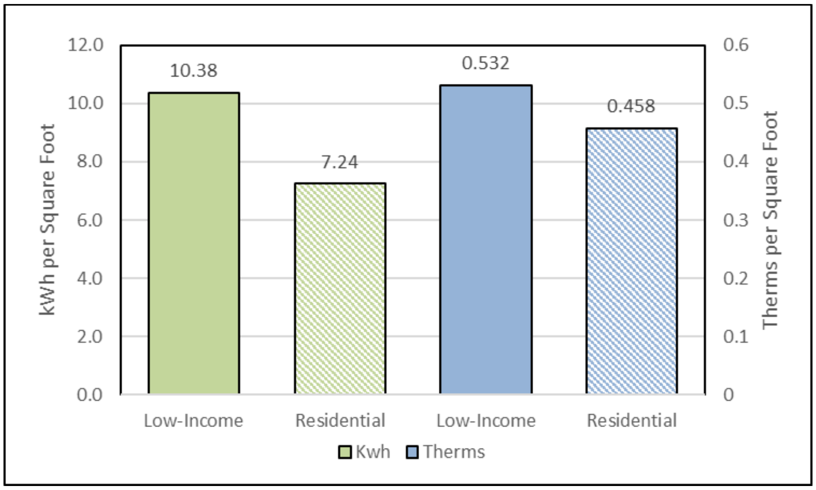


Figure 3-21. Annual 2017 Unadjusted Billed Energy per Square Foot

With smaller homes using more electricity, the low-income group's kWh per square foot averaged over 40 percent higher than residential premises. Possible explanations for this difference are explored below. Therm usage per square foot is also higher for low-income premises, averaging 16 percent more in 2017 than residential.

Housing Characteristics

Housing characteristics obtained from Spokane County Assessor records are shown in the table below. Mean values and differences between the two residential groups are shown for each of the characteristics listed. The last column shows the directional energy use impact of low-income relative to residential. For example, an upward arrow on a characteristic means that considering that attribute alone, low-income energy usage would be expected to be higher than residential usage. A listing of "electric" with a directional indicator means that the relative fuel usage impact only applies to electric and not natural gas usage.

Table 3-23. Comparison of Housing Characteristics

Characteristic	Low-Income	Residential	Difference	Percent Difference	Relative Energy Use Impact
Year Built	1951	1968	(18)		↑
Finished Square Feet	1,403	1,916	(513)	-27%	↓
Market Value	$117,810	$191,966	-$74,155	-39%	↑
Bedrooms	2.8	3.2	(0.44)	-14%	↓
Owner Occupied	62%	85%	-23%		↔
Avista Natural Gas Service	79%	87%	-8%		↑ (Electric)
Air Conditioning	21%	47%	-26%		↓ (Electric)

Low-income homes are 18 years older than residential homes on average. Older homes are more likely to have less thermally efficient building shells than newer homes. The impact of this characteristic is to increase low-income energy usage relative to the residential group. Low-income homes are about 500 square feet smaller on average compared to residential, a substantial twenty-seven percent (27%) percent difference. Market value and market value per square foot are indicators of current quality of construction and building shell efficiency and suggest that low-income homes will use more energy than residential, all other things equal.

The number of bedrooms is not only another measure of size of home, it is a better correlate to size of household and baseload energy usage than is square feet. Fewer bedrooms in low-income housing suggest lower energy usage than residential. Average size of households may also vary between the two groups. Owner occupancy is lower in low-income housing than it is in residential. This variable says more about the occupant's ability to make energy efficiency improvement decisions than it does about relative energy usage.

The percent of the group with natural gas service from Avista is an indication of the predominance of natural gas heating. A lower percentage of low-income homes with natural gas service means a greater reliance on electricity and other fuels for space and water heating in low-income homes than found in the residential group. This characteristic coupled with the age and quality differences of the building shell are likely to explain a large proportion of the greater electric usage per square foot in low-income homes.

Assessor data regarding heating, ventilation and air conditioning (HVAC) equipment is generally less reliable than square footage and year built. Still the data can be useful for comparing relative values between groups. Air conditioning is far less prevalent in low-income homes than it is in residential. This characteristic taken alone suggests less electric usage in low-income homes compared to residential.

Housing Type and HVAC Equipment

It is important to keep in mind that the approach of combing utility records with assessor records results in a data set that is single family construction centric. Utility customers living in multifamily housing are largely omitted from the combined data base of 130 thousand premises. The percentage of the 130 thousand homes by type of housing and residential group is shown in Table 3-24.

Table 3-24. Distribution of Housing Types

Housing Type	Low-Income	Residential
Condos and Townhomes	1.2	2.2
Mobile Homes	10.1	3.9
Plexes	7.0	2.9
Single Family	81.6	91.0
Total	**100.0**	**100.0**

The nearly eighty-two percent (82%) of low-income customers in single family homes is nearly 10 percentage points lower than residential. That difference is made up by a higher percentage of low-income customers in mobile homes and plexes (duplexes, tri and quad).

The distribution of heating equipment is shown in the table below.

Table 3-25. Distribution of Heating Equipment

Heating Equipment	Low-Income	Residential
Forced Air Furnace	81.4	85.7
Zonal	14.0	7.9
Heat Pump	1.1	3.6
Other	3.4	2.9
Total	**100.0**	**100.0**

The majority of heating equipment is some form of forced air system. These include wall and floor systems as well as ducted systems. Zonal is more prevalent in low-income housing, not surprising given the smaller and less expensive housing stock of low-income customers.

Cooling equipment distribution is shown in the table below.

Table 3-26. Distribution of Cooling Equipment

Cooling Equipment	Low-Income	Residential
Central Air Conditioning	18.3	40.9
Heat Pump	1.1	3.6
Other	1.9	2.0
None	78.6	53.5
Total	**100.0**	**100.0**

Central air conditioning is far more prevalent in residential than low-income homes. Assessor data likely understates the prevalence of window units and these relatively inexpensive and inefficient systems are more likely to be found in low-income homes than residential.

Summary – Task 3e

In this section housing attributes and energy usage of low-income and other residential homes are compared using a data set developed for this evaluation of nearly 130,000 premises with Avista residential customer records combined with Spokane County Assessor data. The resulting data is single family centric, with multifamily underrepresented in the results. Data on heating and cooling equipment may also be incomplete or out of date for what is currently used at the premise. Notwithstanding these limitations, the data provide a rich set of information for insights between the differences of low-income and other residential premises.

The average low-income customers used six percent (6%) more electricity per premise in 2017 than other residential customers. Low-income homes were also substantially smaller. With higher use in smaller homes, electric use per square foot in low-income homes was about forty percent (40%) higher than for other residential customers. Analysis to determine why this is the case is beyond the scope of this evaluation but older less efficient homes and greater reliance on electric space heating in low-income homes are at least part of the explanation.

The average low-income customer used 16% less natural gas per premise than other residential customers. On a per square foot basis, natural gas use was sixteen percent (16%) higher in low-income homes than other residential. Much of this difference is likely due to older less efficient building shells in low-income housing units.

Section 4. Analysis of Revenue Effects

In this section we examine the effects of the decoupling mechanisms on Avista's revenue. The objective of Task 4, as stated in the request for proposal, is shown below:

> *"Analysis of the Mechanism's impact on Company revenues (i.e., whether there has been a stabilizing effect)."*

Relating to this objective are the following evaluation questions, also taken from the RFP:

> *"What impact did the Mechanisms have on the Company's revenues (i.e., whether there has been a stabilizing effect)?"*
>
> *What were the causes of the deviation of actual revenue-per-customer from authorized revenue-per-customer?"*
>
> *"Please provide analysis and trends on whether the rate cap was reached and the results of the earnings test."*
>
> *"What factors impacted the deferral and rate changes, and what was the magnitude of that impact? (e.g., weather, customer counts, conservation, economy, etc.)"*
>
> *"What was the impact of the Decoupling deferral on Avista's revenues and rates?"*
>
> *"What was the effect of updates to the decoupling baseline and resulting effects on deferrals under the mechanisms?"*

Our discussion in this section is organized by each of the evaluation questions listed above. Much of the data used to address these questions has been presented in earlier sections of this report and repeated here for ease of discussion and the convenience of the reader.

Has Decoupling Stabilized Revenue

The question as stated in the RFP is:

> *"What impact did the Mechanisms have on the Company's revenues (i.e., whether there has been a stabilizing effect)?"*

This is a straightforward question and easy to answer by comparing actual revenue with actual revenue plus deferred revenue. Here the limiting factor is the relatively short three-year period that the mechanism has been in place. In order to answer this question, we calculated the annual variation in revenue over the 2015 to 2017 period with and without the revenue from decoupling deferrals. We used the coefficient of variation, calculated as the standard deviation divided by the mean, as our measure of variability. Figure 4-1 shows the results of our calculations for electric revenue.

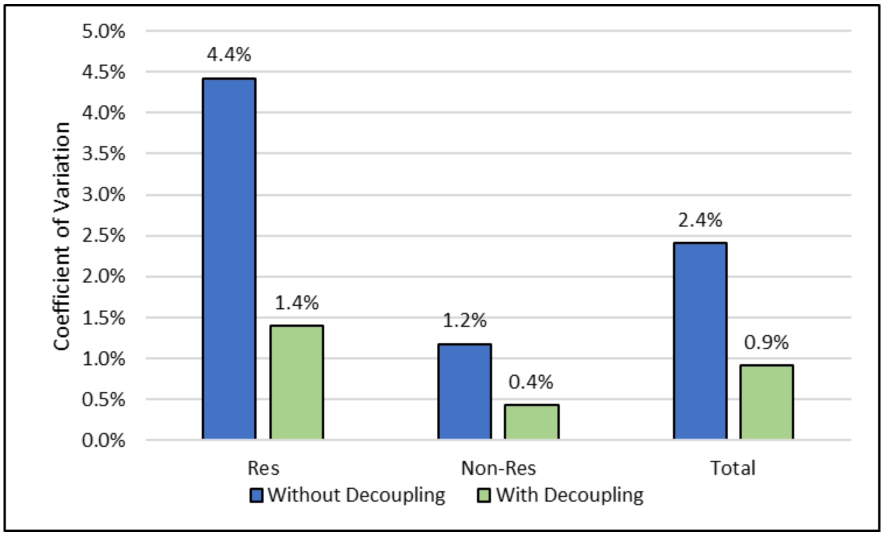


Figure 4-1. Electric Revenue Variability (2015-2017)

The bars labeled "Without Decoupling" refer to base rate revenue only and does not include deferred revenue through the decoupling mechanism. Bars labeled "With Decoupling" include base rate and decoupling deferral revenue. Results are shown for both decoupled rate groups and their total. It is clear from the results shown in Figure 4-1 that there has been a stabilizing effect on revenue as a result of decoupling. For both rate groups, variability is roughly one third of the level without decoupling deferrals.

Variation in natural gas revenue is shown in Figure 4-2.

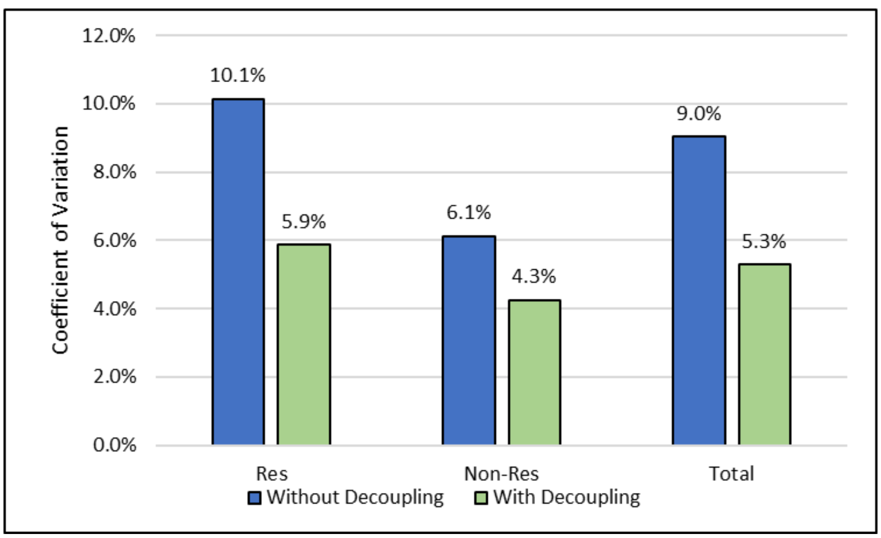


Figure 4-2. Natural Gas Revenue Variability (2015-2017)

Decoupling has also helped to stabilize natural gas revenues. Although the stabilizing effect is not as large for the natural gas rate groups as it is for electric rate groups, revenues from natural gas residential customers are about four percentage points less variable with decoupling than without, a drop in variability of roughly 40%. Variability in the non-residential rate group is nearly two percentage points lower with decoupling, a roughly 30% drop in variability.

Revenue Deviations from Planning Assumptions and Causes

Some of the revenue related evaluation questions have to do with the magnitude and causes for deviations from planning assumptions. These questions as stated in the RFP are:

> *"What were the causes of the deviation of actual revenue-per-customer from authorized revenue-per-customer?"*
>
> *"What factors impacted the deferral and rate changes, and what was the magnitude of that impact? (e.g., weather, customer counts, conservation, economy, etc.)"*

Actual and authorized revenue-per-customer is shown for electric rate groups in Table 4-1.

Table 4-1. Authorized and Actual Electric Decoupled Revenue per Customer

	---------- Residential ----------			---------- Non-Residential ----------		
Year	**Authorized**	**Received**	**Percent Difference**	**Authorized**	**Received**	**Percent Difference**
2015	$709	$673	-5.1%	$4,209	$4,279	1.7%
2016	$735	$685	-6.8%	$4,453	$4,396	-1.3%
2017	$738	$748	1.4%	$4,455	$4,405	-1.1%

Avista received less decoupled revenue per customer from the residential group than was authorized in 2015 and 2016. This pattern was reversed in 2017 when Avista received 1.4% more revenue per customer than authorized. Decoupled revenue per customer for the non-residential rate group exceeded the authorized level in 2015 but fell short in 2016 and 2017. The percent difference shown for residential customers in Table 4-1 closely follows the difference between actual and planned use per customer examined in Section 2. Test year and actual electric usage, customer counts and use per customer are shown for each deferral year in Table 4-2.

Table 4-2. Test Year and Actual Electric Usage, Customers and Use per Customer

	2015			2016			2017		
	Usage (MWh)	**Customers**	**Use per Customer (kWh)**	**Usage (MWh)**	**Customers**	**Use per Customer (kWh)**	**Usage (MWh)**	**Customers**	**Use per Customer (kWh)**
	-------------------- Residential --------------------								
Test Year	2,437,508	207,850	11,727	2,378,478	205,172	11,593	2,378,478	205,172	11,593
Actual	2,323,300	207,371	11,204	2,288,227	209,864	10,903	2,492,293	212,495	11,729
Change from Test Year	(114,208)	(479)	(524)	(90,251)	4,692	(689)	113,815	7,323	136
Percent Change	-4.7%	-0.2%	-4.5%	-3.8%	2.3%	-5.9%	4.8%	3.6%	1.2%
	-------------------- Non-Residential --------------------								
Test Year	2,150,843	35,277	60,970	2,144,857	34,823	61,593	2,144,857	34,823	61,593
Actual	2,179,747	35,265	61,810	2,158,998	35,617	60,618	2,184,830	35,994	60,700
Change from Test Year	28,904	(12)	840	14,142	794	(975)	39,974	1,171	(893)
Percent Change	1.3%	0.0%	1.4%	0.7%	2.3%	-1.6%	1.9%	3.4%	-1.5%

Because Avista's decoupling mechanism is structured to allow a certain level of revenue per customer, more or less customers than planned does not lead to greater deferral balances, all other things equal. Avista relies on volumetric charges to recover a portion of fixed costs for all rate groups and fuels. This causes use per customer to be an important factor in determining deferral balances and decoupling rates through the decoupling mechanism. More specifically, changes in use per customer from levels used in the test year to set decoupled revenue will lead to positive or negative deferral balances depending on the direction of change, all other things equal. Higher use per customer will cause negative deferrals and lower use per customer will result in higher deferrals, again all other things equal.

Considering electric residential as an example, actual decoupled revenue per customer was 6.8% lower than authorized in 2016 (Table 4-1). During the same period customer counts were 2.3 percent higher than the test year and use per customer was 5.8% lower (Table 4-2). Higher than planned customer counts did not drive authorized revenue higher. Rather, as designed and expected, use per customer explains nearly all of the lower than authorized revenue per customer. A comparison of the values in Table 4-1 and Table 4-2 show that almost all of the variance in revenue per customer can be explained by differences in use per customer.

Two important factors causing use per customer to vary from test year are actual weather deviations from normal weather and acquired energy efficiency savings through Avista programs.[65] There are other factors of course but these two are either known in the case of energy efficiency or readily measurable in the case of weather. Changes due to weather are straightforward calculations. Avista provided the weather impacts and supporting monthly details by rate schedule showing the deviation in heating and cooling degree days from normal and the corresponding model coefficient on each weather term. Energy efficiency impacts are calculated as cumulative savings from Avista programs since the test year.

The results of these calculations are shown in Figure 4-3 for the electric residential rate group.

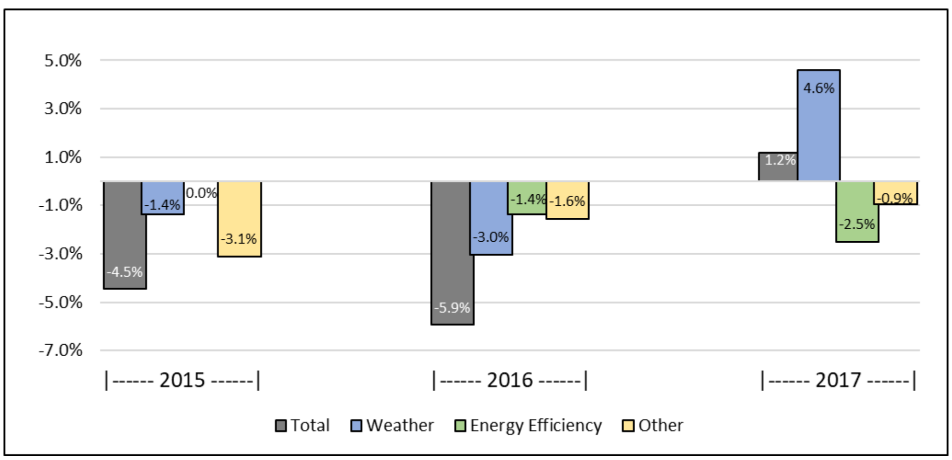


Figure 4-3. Percentage Change in Use per Customer, Electric Residential

Considering 2017 results, use per customer was 1.2% higher than test year assumptions. Weather impacts alone are estimated to have pushed electric residential use per customer 4.6% higher. The 2017 weather impact was largely offset by a 2.5% drop in use per customer due to

[65] For this analysis, normal weather is defined as a thirty-year average.

Avista's energy efficiency achievements. The "Other" category is simply the difference between the total and the readily quantifiable factors of weather and energy efficiency. Other unidentified factors have pushed use per customer lower and have been lessening in influence over time.

For electric residential customers it is clear that weather impacts on use per customer can be large and work in either direction. It is also true that energy efficiency impacts always push use per customer lower and that downward influence becomes more pronounced the further in time an evaluation year is from the test year. Cumulative energy efficiency savings will reset with a new rate case and test year.

Figure 4-4 shows a plot of total and each factor's influence on the percent change in use per customer from the test year for the electric non-residential rate group.

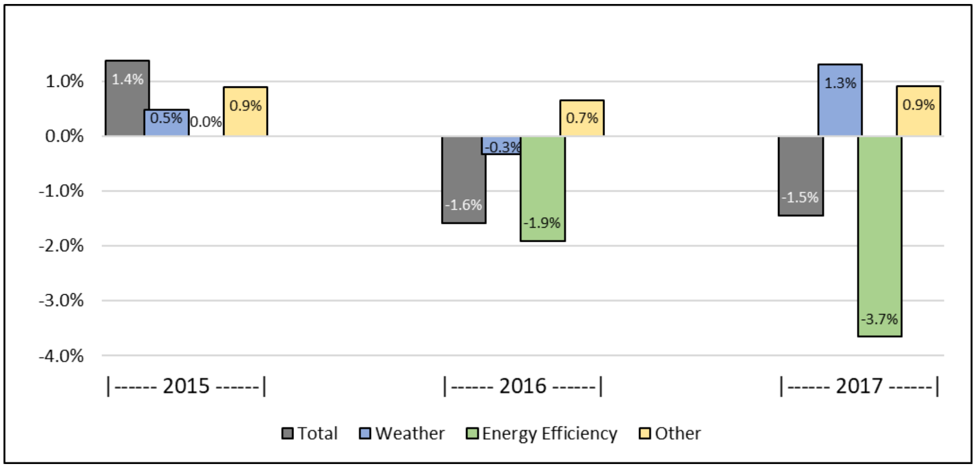


Figure 4-4. Percentage Change in Use per Customer, Electric Non-Residential

Avista's energy efficiency achievements have been the primary factor influencing changing use per customer in the electric non-residential group. From having no influence in 2015 because they were implicitly included in test year assumptions, energy efficiency impacts more than offset weather and other factors in 2017 causing an overall drop in use per customer of 1.5%. Weather appears to be far less influential in electric non-residential customer usage than it is for the electric residential group. Other unidentified factors have pushed use per customer higher at a small but fairly consistent percentage over time. Actual and authorized revenue-per-customer is shown for natural gas rate groups in Table 4-3.

Table 4-3. Authorized and Actual Natural Gas Decoupled Revenue per Customer

	---------- Residential ----------			---------- Non-Residential ----------		
Year	**Authorized**	**Received**	**Percent Difference**	**Authorized**	**Received**	**Percent Difference**
2015	$280	$245	-12.5%	$4,509	$3,835	-14.9%
2016	$347	$299	-13.8%	$5,097	$4,338	-14.9%
2017	$351	$364	3.7%	$5,128	$4,828	-5.9%

For reasons discussed above for electric, the percent difference between authorized and actual revenue per customer shown in Table 4-3 closely follows the difference between actual and planned use per customer. Test year and actual natural gas usage, customer counts and use per customer are shown for each deferral year in Table 4-4.

Table 4-4. Test Year and Actual Natural Gas Usage, Customers and Use per Customer

	2015			2016			2017		
	Usage (MWh)	**Customers**	**Use per Customer (kWh)**	**Usage (MWh)**	**Customers**	**Use per Customer (kWh)**	**Usage (MWh)**	**Customers**	**Use per Customer (kWh)**
	-------------------- **Residential** --------------------								
Test Year	117,011,207	150,186	779	120,721,607	148,995	810	120,721,607	148,995	810
Actual	103,436,220	151,254	684	108,796,187	153,995	706	131,782,922	157,563	836
Change from Test Year	(13,574,987)	1,068	(95)	(11,925,420)	5,000	(104)	11,061,315	8,568	26
Percent Change	-11.6%	0.7%	-12.2%	-9.9%	3.4%	-12.8%	9.2%	5.8%	3.2%
	-------------------- **Non-Residential** --------------------								
Test Year	51,764,097	2,548	20,316	52,606,812	2,584	20,358	52,606,812	2,584	20,358
Actual	45,886,568	2,651	17,309	48,208,894	2,770	17,404	55,684,308	2,918	19,083
Change from Test Year	(5,877,529)	103	(3,006)	(4,397,918)	186	(2,954)	3,077,496	334	(1,275)
Percent Change	-11.4%	4.0%	-14.8%	-8.4%	7.2%	-14.5%	5.8%	12.9%	-6.3%

Considering natural gas non-residential as an example, actual decoupled revenue per customer was 14.9% lower than authorized in 2015 (Table 4-3). During the same period customer counts were 4.0 percent higher than the test year and use per customer was 14.8% lower (Table 4-4). Higher than planned customer counts did not drive authorized revenue higher. Rather, as designed and expected, use per customer explains nearly all of the lower than authorized revenue per customer. A review and comparison of the values in Table 4-3 and Table 4-4 also show that almost all of the variance in revenue per customer can be explained by differences in use per customer.

Two important factors causing use per customer to vary from test year are actual weather deviations from normal weather and acquired energy efficiency savings through Avista programs. There are other factors of course but these two are either known in the case of energy efficiency or readily measurable in the case of weather. Changes due to weather are also straightforward calculations. Avista provided the weather impacts and supporting monthly details by rate schedule showing the deviation in heating and cooling degree days from normal and the corresponding model coefficient on each weather term. Energy efficiency impacts are calculated as cumulative savings from Avista programs since the test year.

The results of these calculations are shown in Figure 4-5 for the natural gas residential rate group.

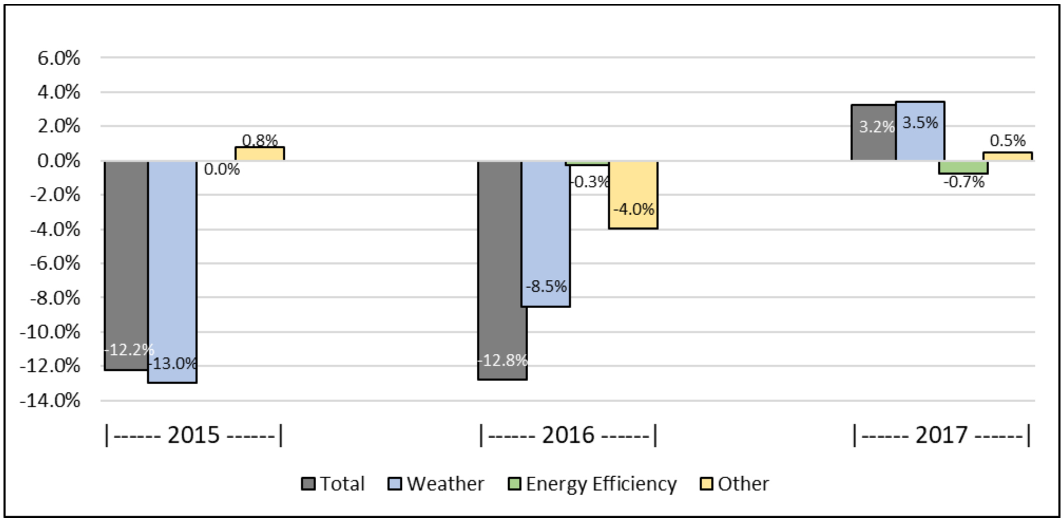


Figure 4-5. Percentage Change in Use per Customer, Natural Gas Residential

Weather is clearly the predominant factor in understanding changes in residential therm use per customer from the test year. The total change in use per customer tracks the warmer than normal heating seasons in calendar years 2015 and 2016 and slightly colder than normal heating season in calendar year 2017. Energy efficiency impacts on use per customer usage are a small factor in understanding overall change from the test year. Natural gas prices have been persistently low, squeezing the cost effectiveness of natural gas efficiency programs. Other unidentified factors were small in 2015 and 2017 but relatively high in 2016. One possible explanation is that the 2016 weather adjustment was understated by the weather normalization model.

Figure 4-6 shows a plot of total and each factor's influence on the percent change in use per customer from test year assumptions for the natural gas non-residential rate group.

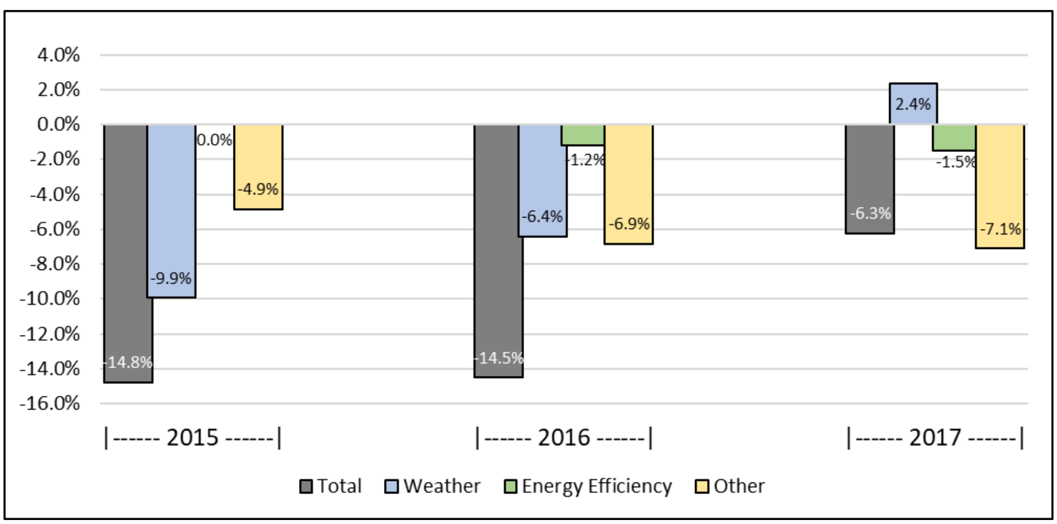


Figure 4-6. Percentage Change in Use per Customer, Natural Gas Non-Residential

Except for weather in 2017, all factors in each year have contributed toward lower use per customer than test year assumptions. Unlike any of the other electric or natural gas rate groups, other factors are an important influence in each of the years examined. Other factors are by definition unquantified but could include increased efficiency outside of Avista's energy efficiency programs, lower use of natural gas due to fuel substitution (e.g. increased use of biomass in cogeneration) and cutbacks in customer facility operations. Weather is also influential although less so than natural gas residential customers. Energy efficiency impacts on use per customer usage are a small factor in understanding overall change from the test year. Again, this could be due in part to persistently low natural gas prices putting pressure on the cost effectiveness of natural gas efficiency programs.

Avista's electric and natural gas energy efficiency programs are discussed in detail in Section 3 and Section 6 of this report. An examination of actual weather experienced over the three evaluation years is presented in Section 2.

Review of Rate Cap and Earnings Test

The question as stated in the RFP is:

"Please provide analysis and trends on whether the rate cap was reached and the results of the earnings test?

The earnings test is calculated to determine the amount of excess earnings, earnings over the allowed rate of return. If excess earnings exist, Avista shares 50 percent of the excess earnings with the residential and non-residential rate groups. Table 4-5 shows the level of shared revenue (50% of excess revenue) in each year for the electric system and natural gas system.

Table 4-5. Earning Test Shared Revenue

Year	Electric	Natural Gas
	(thousands of dollars)	
2015	$899	$0
2016	$2,597	$2,927
2017	$1,493	$2,600

Normalized revenue for the applicable year is used to determine the split of shared revenue between the two rate groups. Shared earnings are paid by Avista to each customer rate group through the decoupling rate established with each annual filing.

The decoupling settlement stipulates that the change in the decoupling rate cannot add more than 3 percent to expected revenue before the change. If necessary, decoupling rates are capped to a level that limits the expected change in revenue to 3 percent and the amount of revenue that was not allowed to be amortized in the new decoupling rate is carried forward. Table 4-6 shows the annual history of rate cap results for each fuel and rate group.

Table 4-6. History of Rate Cap Results - Was Rate Cap Reached?

	Electric		Natural Gas	
Deferral Year	Residential	Non-Residential	Residential	Non-Residential
2015	Yes	No	Yes	Yes
2016	No	No	Yes	No
2017	No	No	No	No

On the electric side, the 3% cap on annual rate increases from the decoupling rate was only reached one out of six possible times. After reaching the rate cap based on 2015 results, the electric residential rate group did not reach the rate cap in 2016 and 2017. For natural gas, the rate cap was reached 3 of 6 times, twice for residential customers and once for non-residential. Electric non-residential is the only rate group that has not reached the rate cap. None of the four rate groups were subject to the decoupling rate cap in 2017, meaning there were no unamortized revenue balances to carry forward to 2018.

Review of Deferrals

The question as stated in the RFP is:

> *"What was the impact of the Decoupling deferral on Avista's revenues and rates?"*
>
> *"What was the effect of updates to the decoupling baseline and resulting effects on deferrals under the mechanisms?"*

As reported earlier in this section, deferrals have had the effect of lowering the variability of annual revenue. This is true for all rate groups. Allowed electric revenue (revenue with deferrals), base rate revenue and decoupling deferrals are shown in Table 4-7.

Table 4-7. Electric Revenue from Decoupled Rate Groups

	Revenue with Deferrals			Base Rate Revenue			Decoupling Deferrals		
	Residential	Non-Residential	Total	Residential	Non-Residential	Total	Residential	Non-Residential	Total
Decoupled Year	*(millions of dollars)*			*(millions of dollars)*			*(millions of dollars)*		
2015	217.2	213.8	431.0	210.0	216.2	426.2	7.2	(2.4)	4.8
2016	213.9	213.1	427.0	203.6	211.1	414.8	10.3	2.0	12.3
2017	220.0	214.9	434.9	222.1	213.2	435.3	(2.1)	1.7	(0.4)
Mean	217.0	213.9	431.0	211.9	213.5	425.4	5.1	0.4	5.6
Std Dev	3.0	0.9	3.9	9.4	2.5	10.3	6.4	2.4	6.3
Coefficient of Variation	0.014	0.004	0.009	0.044	0.012	0.024	NA	NA	NA

The calculations for the coefficient of variation, a measure of variability, are also shown in Table 4-7. Allowed natural gas revenue (revenue with deferrals), base rate revenue and decoupling deferrals are shown in Table 4-8.

Table 4-8. Natural Gas Revenue from Decoupled Rate Groups

Decoupled Year	Revenue with Deferrals			Base Rate Revenue			Decoupling Deferrals		
	Residential	Non-Residential	Total	Residential	Non-Residential	Total	Residential	Non-Residential	Total
	(millions of dollars)			*(millions of dollars)*			*(millions of dollars)*		
2015	108.5	36.9	145.4	103.2	35.2	138.3	5.3	1.7	7.0
2016	112.3	35.7	148.0	105.1	33.7	138.8	7.2	2.0	9.2
2017	121.5	38.8	160.3	123.5	38.0	161.5	(2.0)	0.8	(1.1)
Mean	114.1	37.1	151.2	110.6	35.6	146.2	3.5	1.5	5.0
Std Dev	6.7	1.6	8.0	11.2	2.2	13.2	4.8	0.6	5.4
Coefficient of Variation	0.059	0.043	0.053	0.101	0.061	0.090	NA	NA	NA

Because deferred revenue has averaged above zero for all rate groups, deferrals have worked to increase revenue from base rates. As has been discussed, much of the increase has been due to lower use per customer due to weather, especially in electric residential, natural gas residential and natural gas non-residential. Avista's energy efficiency programs have also worked to lower use per customer, especially for electric rate groups. Going forward, weather could just as easily have the opposite effect causing negative deferrals and higher base rate revenue than revenue with deferrals. The same is not true for Avista's energy efficiency savings, which always work in the direction of lower use per customer and increasing deferred revenues. The impact of energy efficiency has been especially significant in explaining changes from test year assumptions in the electric non-residential group.

Deferral balances and decoupling rates are shown in Table 4-9.

Table 4-9. Summary of Deferral Balances and Decoupling Recovery Rates

----------------------------- Electric -----------------------------							
		Residential Group			Non-Residential Group		
	Notes	2015	2016	2017	2015	2016	2017
Deferred Revenue ($)		7,167,748	10,288,205	-2,092,790	-2,373,472	1,967,777	1,735,911
Requested Recovery ($)	A	7,360,678	10,913,950	-2,765,635	-3,081,249	864,012	1,170,966
Customer Surcharge (Rebate) Revenue ($)		6,485,021	10,913,950	-2,765,635	-3,081,249	864,012	1,170,966
Carryover Deferred Revenue ($)		875,657	0	0	0	0	0
Decoupling Rate (Schedule 75) ($/kWh)	B	0.00263	0.00445	-0.00116	-0.00143	0.00040	0.00054
Incremental Revenue (Percent)		3.00%	2.00%	-5.78%	-1.40%	0.40%	0.14%
Limited by 3% Cap?		Yes	No	No	No	No	No
----------------------------- Natural Gas -----------------------------							
		Residential Group			Non-Residential Group		
	Notes	2015	2016	2017	2015	2016	2017
Deferred Revenue ($)		5,317,198	7,152,977	-1,972,082	1,736,736	2,002,654	840,286
Requested Recovery ($)	A	5,750,096	7,652,369	-3,441,586	1,879,152	2,212,881	407,719
Customer Surcharge (Rebate) Revenue ($)		3,488,984	6,951,431	-3,441,586	1,108,839	2,212,881	407,719
Carryover Deferred Revenue ($)		2,261,112	700,938	0	770,313	0	0
Decoupling Rate (Schedule 175) ($/therm)	B	0.02927	0.05580	-0.02720	0.02108	0.03904	0.00691
Incremental Revenue (Percent)		3.00%	3.00%	-10.08%	3.00%	2.95%	-6.13%
Limited by 3% Cap?		Yes	Yes	No	Yes	No	No
A: Requested recovery is equal to deferred revenue after adjusting for shared excess earnings (if applicable), deferral balance carryover from prior year (if any), interest, and revenue related expenses.							
B: Decoupling rates Schedule 75 (electric) and Schedule 175 (natural gas) take effect on November 1st of the following year. For example, rates shown in the 2016 column have an effective date of November 1, 2017							

Comparing deferred revenue with the requested recovery shows the importance of deferral balances in determining decoupling rates. They are not the only factor, however, and in some instances other factors are actually larger than the deferral balance. This was the case for electric non-residential in 2016, for example, when the requested recovery was only 44 percent of deferred revenue ($ 864,012 / $ 1,967,777), due mainly to shared excess earnings.

The decoupling baseline or test year is another factor that comes into play when analyzing deferral balances and the impacts from various factors, such as energy efficiency. The test year used for 2015 deferral calculations was a projection of 2015. The test year for 2016 and 2017 is a 12-month period ending September 2014. The practical implication of this change in baseline for actual weather compared to normal weather are insignificant. However, Avista's energy efficiency programs have a greater impact the further in time the actual calendar year is from the test year. So, moving the baseline from 2015 to 12 months ending September 2014 resulted in a larger variance in use per customer due to Avista's energy efficiency programs. The same is true for the "other" category of factors impacting use per customer which would include efficiency gains outside of Avista's programs.

Removing the influence of weather from deferred revenue provides another way to view the impacts of Avista's energy efficiency achievements and "other" unexplained influences on deferral balances. Table 4-10 shows actual deferred revenue and deferred revenue estimated at normal weather.

Table 4-10. Deferred Revenue at Normal Weather

--------------------------------- Electric ---------------------------------						
	Residential Group			**Non-Residential Group**		
	2015	**2016**	**2017**	**2015**	**2016**	**2017**
Deferred Revenue	7,167,748	10,288,205	-2,092,790	-2,373,472	1,967,777	1,735,911
Weather Impact on Deferrals	2,416,743	5,587,227	-8,618,230	-451,215	465,250	-1,646,265
Deferred Revenue at Normal Weather	4,751,005	4,700,978	6,525,440	-1,922,257	1,502,527	3,382,176
--------------------------------- Natural Gas ---------------------------------						
	Residential Group			**Non-Residential Group**		
	2015	**2016**	**2017**	**2015**	**2016**	**2017**
Deferred Revenue	5,317,198	7,152,977	-1,972,082	1,736,736	2,002,654	840,286
Weather Impact on Deferrals	5,739,128	4,720,021	-1,961,267	1,262,997	967,162	-380,599
Deferred Revenue at Normal Weather	-421,930	2,432,956	-10,815	473,739	1,035,492	1,220,885

Deferred revenue at normal weather is calculated by subtracting the weather impacts on deferrals from actual deferred revenue. The weather impact is estimated using Avista's weather adjustment coefficients as reported in weather adjustment calculations workbooks.[66] Deferred revenue at normal weather shows the same patterns of influence of Avista's energy efficiency programs and other unidentified factors on deferred revenue. Consider, for example, the electric non-residential rate group. Deferred revenue estimated at normal weather was negative in 2015 and increasingly positive in 2016 and 2017. This is the same pattern shown in Figure 4-4 where the net influence of Avista's energy efficiency programs and other factors excluding weather

[66] See Data Request number 76.

lead to higher use per customer in 2015 (and negative deferrals) and progressively lower use per customer (and positive deferrals) in 2016 and 2017.

Summary – Task 4

Avista's decoupling mechanism has had a stabilizing effect on revenue, reducing variability to between 30 and 70 percent of variability without decoupling. On the electric side, the 3% cap on annual rate increases from the decoupling rate was only reached one out of six possible times when it came into effect for electric residential in 2015. For natural gas, the rate cap was reached 3 of 6 times, twice for residential customers and once for non-residential. Electric non-residential is the only rate group that has not reached the rate cap. *None of the four rate groups were subject to the decoupling rate cap in 2017.*

Because deferred revenue has averaged above zero for all rate groups, deferrals have worked to increase revenue from base rates. Much of the increase has been due to lower use per customer due to weather, especially in electric residential, natural gas residential and natural gas non-residential. Avista's energy efficiency programs have also worked to lower use per customer, especially for electric rate groups. The impact of energy efficiency has been especially significant in explaining changes from test year assumptions in the electric non-residential group.

Section 5. Fixed Costs and Charges, Non-Decoupled Customers

In this section we examine fixed costs and fixed charges for electric and natural gas customer classes.

The objective of Task 5, as stated in the request for proposal, is shown below:

> *"Analysis of the extent to which fixed costs are recovered in fixed charges for the customer classes, excluded from the Mechanisms."*

Relating to this objective is the following evaluation question, also taken from the RFP:

> *"How much of the Company's fixed costs recovered from non-decoupling customer classes are recovered in fixed charges?"*

The scope of this section was expanded to include decoupled electric and natural gas customer classes to facilitate comparison to customer classes excluded from the decoupling mechanisms. To address the evaluation objective, it is necessary to compare revenues from fixed charges to fixed costs for these customer classes. Fixed cost and revenue collected from fixed charges was provided by Avista in response to data request (DR) 89. Beginning with electric customer classes, we examine the recovery of fixed cost through fixed charges and the relationships presented in the data. Throughout the discussion it is useful to keep in mind that the basis for cost allocation changed between 2015 and 2016/2017.[67]

Electric Customers

Annual revenue from fixed charges and fixed costs are shown for electric customer classes in Table 5-1.

Table 5-1. Electric Revenue from Fixed Charges and Fixed Cost (thousands of dollars)

		Decoupled				Non-Decoupled	
		Residential	General Service	Large General Service	Pumping Service	Extra Large General Service	Street & Area Lighting
		Schedules					
	Total	1, 2	11, 12	21, 22	31, 32	25	41-49
-------------------- 2015 --------------------							
Revenue from Fixed Charges	52,730	21,450	6,728	12,061	527	5,292	6,672
Fixed Cost	382,117	191,696	43,845	86,254	9,376	43,585	7,360
Percent Recovered from Fixed Charges	13.8%	11.2%	15.3%	14.0%	5.6%	12.1%	90.7%
-------------------- 2016 --------------------							
Revenue from Fixed Charges	52,943	21,969	6,883	11,447	546	5,271	6,828
Fixed Cost	400,668	202,356	47,747	87,775	9,116	45,439	8,235
Percent Recovered from Fixed Charges	13.2%	10.9%	14.4%	13.0%	6.0%	11.6%	82.9%
-------------------- 2017 --------------------							
Revenue from Fixed Charges	53,013	22,226	6,955	11,396	533	5,426	6,475
Fixed Cost	408,126	210,268	48,363	86,777	9,144	45,287	8,286
Percent Recovered from Fixed Charges	13.0%	10.6%	14.4%	13.1%	5.8%	12.0%	78.1%

[67] For 2015 the cost of service study used for the General Rate Case (GRC) for electric (UE-140188) and natural gas (UG-140189) was the basis for cost allocation factors. The cost of service study used for the GRC for electric (UE-150204) and natural gas (UG-150205) was the basis for cost allocation factors used for 2016 and 2017. These cost allocation factors were adjusted for actual customer counts and usage levels for the analysis reported in this section.

Over the 2015-2017 period fixed charges for total electric have averaged slightly higher than 13 percent of fixed cost. The percentage has fallen slightly since 2015. The customer class that covers the highest percentage of fixed costs through fixed charges is street and area lighting, just over 90 percent in 2015 and falling to 78 percent in 2017. The customer class collecting the smallest percentage of fixed costs through fixed charges is pumping services. Pumping services have averaged a little less than 6 percent recovery of fixed cost through fixed charges. About 11 percent of residential fixed costs are recovered through fixed charges. The percentage has fallen from 11.2 percent in 2015 to 10.6 percent in 2017. The percentage of fixed cost recovered through fixed charges from general services and large general services have each fallen about one percentage point between 2015 and the two-year period 2016 and 2017.

Natural Gas Customers

Annual revenue from fixed charges and fixed costs are shown for natural gas customer classes in Table 5-2.[68]

Table 5-2. Fixed Cost and Fixed Charges, Non-Decoupled Natural Gas Customer Classes

		Decoupled			Non-Decoupled	
		Residential	Large General Service	High Load Factor Large General Service	Interrupt-ible Service	Transportation Service
		Schedules				
	Total	101, 102	111, 112	121, 122	131, 132	146
-------------------- 2015 --------------------						
Revenue from Fixed Charges	19,519	16,471	2,748	70	0	229
Fixed Cost	81,405	63,593	13,652	1,166	173	2,822
Percent Recovered from Fixed Charges	24.0%	25.9%	20.1%	6.0%	0.0%	8.1%
-------------------- 2016 --------------------						
Revenue from Fixed Charges	20,544	16,896	3,324	78	0	245
Fixed Cost	84,923	69,266	11,542	818	184	3,113
Percent Recovered from Fixed Charges	24.2%	24.4%	28.8%	9.6%	0.0%	7.9%
-------------------- 2017 --------------------						
Revenue from Fixed Charges	21,184	17,287	3,536	108	0	253
Fixed Cost	89,681	72,938	12,464	793	179	3,308
Percent Recovered from Fixed Charges	23.6%	23.7%	28.4%	13.7%	0.0%	7.6%

Over the 2015-2017 period fixed charges for total natural gas have averaged around 24 percent of fixed cost. Residential customers cover the highest percentage of fixed costs through fixed charges, ranging from a high of 25.9 percent in 2015 to a low of 23.7 in 2017. The two non-residential decoupled customer classes have both seen a marked increase in the percentage of fixed costs recovered through fixed charges since 2015. This sort of change is likely due to rate restructuring between the UG-140189 and UG-150205.

Non-decoupled customer classes recover the smallest percentage of fixed cost through fixed charges. Fixed charges revenue as a percentage of fixed cost is zero for interruptible services.

[68] Avista's natural gas cost of service studies use different customer groupings than the decoupling mechanism. The cost of service roll-up does not differentiate Schedules 112, 122, or 132 which were excluded from the decoupling mechanism. Consequently the 111/112 and 121/122 columns overstate the decoupled amounts and the Schedule 131/132 column understates non-decoupled sales service. The difference is not considered material for the cost of service portion of this evaluation.

Fixed costs are a very small level of the total costs for this customer class. The percentage of fixed cost recovered through fixed charges from transportation service has averaged a little less than 8 percent and has been falling between 2015 and 2017.

Summary – Task 5

Avista recovers about 13 percent of total electric fixed cost through fixed customer charges, trending only slightly lower over the 2015-2017 period. On the natural gas side, fixed charges have averaged nearly 24 percent of fixed costs between 2015 and 2017. The percentage has moved higher for decoupled natural gas non-residential customer classes and lower for residential.

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Section 6. Analysis of Conservation Achievement

In this section of the evaluation, we use results of DSM Annual Conservation Report & Cost Effectiveness Analyses and the Annual Conservation Plans. There are three questions (Figure 6-1):

- First, what is the impact of conversions from electric to natural gas on decoupling revenue?
- Second, has decoupling had an impact on natural gas conservation savings?
- Third, has decoupling had an impact on electric conservation savings (leaving out the commitment to an additional five-percent (5%) energy saving)?

Conservation achievement through regional market transformation (which Avista co-funds through the Northwest Energy Efficiency Alliance) is left out of all analysis in this section of the report.

First, we examine the impact of fuel conversions on decoupling revenue. Then we examine whether decoupling has had an impact on energy savings.

Task 6: An analysis of each Mechanism's impact on conservation achievement, in total and by sector (residential, low-income, non-residential), and identification of conclusive or meaningful trends in the performance of the Company's electric and natural gas conservation programs since the inception of the Mechanisms (did the Company achieve a higher level of savings with the mechanisms in effect). This analysis should be based on information already available as part of the Company's biennial conservation achievement evaluations filed with the Commission including changes to program delivery strategies as reported in annual evaluations, significant changes in program budgets, or reported savings levels.

6a For the electric and gas conservation programs, what impact has the shift in customers (electric to natural gas) due to fuel conversions had on decoupling revenue?

6b Have the Mechanisms had an impact on natural gas conservation savings?

6c Have the Mechanisms had an impact on electric conservation savings (not including the decoupling commitment to an additional 5% savings)?

Figure 6-1. Task 6 - Conservation Achievement

What is the Impact of Fuel Conversion on Decoupling Revenue?

Evaluation question 6a (Figure 6-1) asks, "For the electric and gas conservation programs, what impact has the shift in customers (electric to natural gas) due to fuel conversions had on decoupling revenue?" The goal is to decrease electric usage by increasing sales of natural gas. First, three observations to set the context:

- For 2015, there was no decoupling revenue, so there was no fuel conversion effect on decoupling revenue for 2015.
- For 2016, decoupling revenue was limited to a partial collection (or rebate) of revenue from decoupling in November, phased in using billing cycles and full collection in December. For January through October of 2016 there was no decoupling revenue recovery or rebate. This means any effect demonstrated for calendar 2016 is quite small.
- For 2017, there is a full year of application of the decoupling adjustment to customer bills. This means calendar 2017 is the first year to show the full effect of decoupling revenue recovery and/or rebate.

For the fuel conversion program, change is directional. Fuel conversion operates in only one way, from electric to natural gas. Conversion begins by disconnection of electric end-use equipment, so analysis begins on the electric side. From an electric perspective, yearly kWh conversion savings as a percentage of overall savings achievement by group is shown for Electric Residential in Table 6-1 and for Electric Nonresidential in Table 6-2:[69] From an electric perspective,

- the residential percentage converted for 2016 is about 23 percent of residential overall savings achievement; for 2017 it is just under 31 percent (Table 6-1).
- and for low-income, conversion is about 50 percent of overall savings achievement for 2016; for 2017 it is 73 percent (Table 6-1).
- low-income converted kWh is just under 3 percent of residential converted kWh in 2016; for 2017 it is 5 percent (calculated from "Converted kWh" columns in Table 6-1).
- the non-residential percentage of overall conservation achievement due to conversions is 2.1 percent for 2016; for 2017 it is 2.6 percent (Table 6-2).

[69] 2016 Washington DSM Annual Conservation Report & Cost-Effective Analysis, June 1, 2017, Table ES-1; 2017 Washington DSM Annual Conservation Report & Cost-Effective Analysis, June 1, 2018, Table ES-1.

Table 6-1. Electric Residential Conversions as Percentage of Conservation Achievement (kWh)

Electric Residential kWh (Including Low Income)						
Decoupled Group	2016			2017		
	kWh	Converted kWh	Percentage Converted	kWh	Converted kWh	Percentage Converted
Residential	43,083,551	9,766,855	22.7%	33,376,237	10,237,036	30.7%
Low Income	546,066	273,628	50.1%	710,204	518,748	73.0%
Total	43,629,617	10,040,483	23.0%	34,086,441	10,755,784	31.6%

Table 6-2. Electric Non-Residential Conversion as Percentage of Conservation Achievement (kWh)

Electric Nonresidential kWh						
Decoupled Group	2016			2017		
	kWh	Converted kWh	Percentage Converted	kWh	Converted kWh	Percentage Converted
Nonresidential	38,226,357	805,779	2.1%	41,930,099	1,070,262	2.6%

Residential Electric: The Schedule 75 Residential electric decoupling rate (from Task 2) is $0.00263 per kWh for the first rate-year and $0.00445 for the second rate-year (in the case of the Residential Electric group, for both years, these are surcharges to customers). Since the specially defined year for application of rates runs for the twelve months from November through October, the electric decoupling rate for the 2016 cannot be used for the full calendar 2016 (the value is zero for January through October of 2016, then $0.00263 per kWh for November and December 2016).

This value also applies for January through October 2017. The value for the second rate-year applies to the last two months (November and December) of 2017. Converted kWh is taken from the Washington 2017 DSM Annual Conservation Report & Cost-Effectiveness Analysis (see note in Table 6-3). The ratio of Residential kWh usage per time block as shown in the columns of Table 6-3 is developed from monthly energy use, summed over each time block and then divided by the total Residential energy use. This ratio is used to spread the application of the Converted kWh.[70] As shown in the last row and final column of Table 6-3, conversion from electric to natural gas is estimated to cause $29,389 of fixed cost Electric Decoupling Rate Adjustment over November 2016 through December 2017.

[70] Electric usage (kWh per month) is shown in Section 2 of this evaluation. No allocation is perfect and other allocations could also be used. Reporting of conserved kWh is typically on a first-year projected basis for projects completed during a calendar year. Converted kWh is treated on the same basis for allocations to table columns and estimation of the total.

Dollar values in the columns result from the application of electric decoupling rate values. The value shown, $29,389, is an estimate. This estimate is determined in part by the allocation of full year Converted kWh savings by time blocks to which the different values of Electric Decoupling Rate Adjustment apply.[71]

The values in the row next to the bottom row of the table are *the Electric Decoupling Rate Adjustment surcharges which would have applied if there had been no conversion* and equipment had remained in place connected to the electric system. Since these devices were disconnected from the system, customers retained a net value of $29,389. From a Company perspective this represents a net loss of $29,389 of Electric Residential Decoupling Revenue.

Table 6-3. Residential Fuel Conversion Program Savings

Allocation of Residential Electric Decoupling Revenue Based on Gross Verified Savings (kWh)

	Converted kWh 16-17	Jan-Oct 16	Nov+Dec 16	Jan-Oct 17	Nov+Dec 17	Total
Converted kWh 16-17	16,541,961					
Residential kWh		1,852,650,051	416,441,453	2,062,581,745	439,889,023	4,771,562,272
Weights		0.3883	0.0873	0.4323	0.0922	1.0000
Allocated Converted kWh	16,541,961	6,422,732	1,443,711	7,150,519	1,524,999	16,541,961
Decoupling Rate		0	0.00263	0.00263	0.00445	
Decoupling Revenue			$3,797	$18,806	$6,786	$29,389
			Surcharge	Surcharge	Surcharge	Surcharge

The Converted kWh 16-17 is from Page 2, Table 2: Washington Electric Portfolio Evaluation Results, Appendix C (2016-2017 Electric Impact Evaluations) of the Washington 2017 DSM Annual Conservation Report & Cost Effectiveness Analysis, June 1, 2018. Electric Residential and Electric Residential Low Income conversions have been combined.

For Residential Electric, each time block in which the decoupling rate is applied represents a surcharge to the customers and would have been paid by the customers if they had not disconnected equipment from electric service. However, here we examine the loss of kWh sales due to conversion away from Electric Residential service, so the surcharges that would have been paid by customers are not paid, representing a gain for the customers and a loss of Electric Residential decoupling revenue to the Company.[72] The Company would eventually recover this revenue through future decoupling rate adjustments and surcharges so that the net effect is a transfer of income from all customers within the rate group to those customers that convert from electric to natural gas.

Nonresidential Electric: The Schedule 75 Nonresidential Group electric decoupling rate is negative $0.00144 for the first rate-year (a rebate to customers) and positive $0.00040 (a surcharge to customers) for the second rate year. Since the specially defined year for application of rates runs from November through October, the decoupling rate for the 2016 (negative

[71] Results are not directly metered, they are modelled using assumptions.

[72] We treat conversion here the same way that conservation is treated. If conservation occurs during a calendar year, its value for that year is counted (“first year energy savings”). Generally, this is a modeled value based on a combination of empirical measurement and engineering analysis and assumptions. It is not the actual metered value for that year, except in special projects with quasi-experimental or experimental designs.

$0.00144) can be used for the two months to which it applies in calendar 2016. This is also the rate for January through October 2017. The positive value of $0.00040 then applies for November and December of 2017.

Results for Nonresidential Electric conversions are shown in Table 6-4. The values in the table represent what would have happened if the electric equipment was not disconnected. In this instance, a negative decoupling rate for the first rate-year (a rebate) has a much larger effect than the customer surcharge Electric Decoupling Rate Adjustment for the two months to which it applies in the second rate-year. The net result is a rebate of $11,807. However, in fact, the customers did disconnect the electric equipment. So, on the electric side their net rebate was foregone and can be treated as a cost of $11,807. This means the Company gained $11,807 by not having to pay out this amount in rebates to customers.

Table 6-4. Allocation of Nonresidential Revenue based on Gross Verified Savings (kWh)

Allocation of Nonresidential Electric Decoupling Revenue Based on Gross Verified Savings (kWh)						
	Converted kWh 16-17	Jan-Oct 16	Nov+Dec 16	Jan-Oct 17	Nov+Dec 17	Total
Converted kWh 16-17	1,810,107					
Nonresidential kWh		1,797,755,804	345,379,736	1,820,084,174	259,943,247	4,223,162,961
Weights		0.4257	0.0818	0.4310	0.0616	1.0000
Allocated Converted kWh	1,810,107	7,041,738	1,352,839	7,129,197	1,018,187	16,541,961
Decoupling Rate		0	-0.00144	-0.00144	0.00040	
Decoupling Revenue			-$1,948	-$10,266	$407	-$11,807
			Rebate	Rebate	Surcharge	Rebate

The Converted kWh 16-17 is from Page 2, Table 2: Washington Electric Portfolio Evaluation Results, Appendix C (2016-2017 Electric Impact Evaluations) of the Washington 2017 DSM Annual Conservation Report & Cost Effectiveness Analysis, June 1, 2018. Nonresidential Groups E2A (General Services)), E2B (Large General Services Included in Decoiupling) and E2C (Pumping) conversions have been combined.

Residential Natural Gas: By means of similar calculations, the new sales of therms effect on Residential Natural Gas decoupling revenue from increased gas sales is shown in the bottom two rows of Table 6-5. Here the magnitude of the change is only $1,079. Since natural gas sales were increased and the Natural Gas Residential Group Decoupling Rate Adjustment is on a per therm sold basis, the Natural Gas Residential Group received an additional cost of $1,079. From a Company perspective this is $1,079 in additional Residential Natural Gas Decoupling Revenue.

Table 6-5. Residential Gas Decoupling Revenue Based on Gross Verified Savings (therms)

Allocation of Residential Natural Gas Decoupling Revenue (Gross Verified Savings - Therms)						
	Conversion Increased Sales (2016-2017) (Therms)	Jan-Oct 16	Nov+Dec 16	Jan-Oct 17	Nov+Dec 17	Total
Converted Therms 16-17	1,136,582					
Residential Therms		79,954,265	25,961,006	192,721,248	30,034,533	328,671,052
Weights		0.2433	0.0790	0.5864	0.0914	1.0000
Allocated Converted Therms	1,136,582	276,491	21,839	12,806	1,170	312,306
Decoupling Rate		0	0.02927	0.02927	0.05580	
Decoupling Revenue			$639	$375	$65	$1,079
			Surcharge	Surcharge	Surcharge	Surcharge

The Converted Therms 16-17 is from Page 20, Table 2-15: Residential Reported Participation and Savings, Appendix D (2016-2017 Natural Gas Impact Evaluation) of the Washington 2017 DSM Annual Conservation Report & Cost Effectiveness Analysis, June 1, 2018. Natural Gas Residential and Natural Gas Low Income conversions have been combined.

Nonresidential Natural Gas: By means of similar calculations, the converted portions of decoupling revenue for residential natural gas is shown in the bottom two rows of Table 6-6. Here the magnitude of the change is $1,384. Since there is a per therm surcharge for additional natural gas sales for the Nonresidential Natural Gas Group, this results in an additional Nonresidential Decoupling Revenue Charge of $1,384. This is a cost to customers of $1,384 and from a Company perspective an increase in Nonresidential Natural Gas Decoupling Revenue of $1,384.

Table 6-6. Nonresidential Gas Decoupling Revenue (Gross Verified Savings - therms)

Allocation of Nonresidential Natural Gas Decoupling Revenue (Gross Verified Savings - Therms)

	Conversion Increased Sales (2016-2017) (Therms)	Jan-Oct 16	Nov+Dec 16	Jan-Oct 17	Nov+Dec 17	Total
Converted Therms 16-17	88,088					
Nonresidential Therms		36,397,057	10,570,164	44,277,280	11,884,139	103,128,640
Weights		0.3529	0.1025	0.4293	0.1152	1.0000
Allocated Converted Therms	88,088	31,089	9,029	37,820	10,151	88,088
Decoupling Rate		0	0.02108	0.02108	0.03904	
Decoupling Revenue			$190	$797	$396	$1,384
			Surcharge	Surcharge	Surcharge	Surcharge

The Converted Therms 16-17 is from Page 19, Table 2-14: Avista Nonresidential Reported Participation and Savings, Appendix D (2016-2017 Natural Gas Impact Evaluation) of the Washington 2017 DSM Annual Conservation Report & Cost Effectiveness Analysis, June 1, 2018. Natural Gas General Service and Natural Gas Large General Service Included (Decoupled Groups G2A & G2B) have been combined.

Summary - Impact of Fuel Conversion on Decoupling Revenue

The impact of fuel conversion on decoupling revenue is small.

- For residential customers, there was a decoupling tariff adjustment of (cost to the customer) $29,389 for disconnecting electric service to equipment. Adding natural gas equipment as replacements, additional natural gas sales caused a decoupling tariff adjustment (cost to the customer) of $1,079, for a net cost to customers of $29,868. At the same time, net residential effect on Residential (combined) Electric and Natural Gas Decoupling Revenue was a gain of $29,868 to the Company.
- For Nonresidential customers, there was a decoupling tariff adjustment (cost to the customer) of $11,807 which would have been rebated had equipment remained in place. In addition, there was a cost to the customer of $1,384 for the decoupling cost adder per therm for additional therm sales, for a net cost of $13,191. From the Company's perspective, this is a gain of $13,191 in Nonresidential (combined) Electric and Natural Gas Decoupling Revenue benefit.

Have the Mechanisms had an Impact on Natural Gas or Electric Conservation?

This question combines evaluation analysis questions 6b and 6c in Figure 6-1. For electric conservation savings, the decoupling commitment to an additional five-percent (5%) savings is excluded from analysis: the question concerns conservation beyond the five-percent decoupling commitment. We first look at conservation savings totals. The look at totals (electric and natural gas separately) is followed by examination of conservation savings for each of the three electric decoupling groups (residential, low-income, non-residential). Then, we examine each of the three natural gas decoupling groups (residential, low-income and non-residential). *In each of these analyses, we conclude there is no evidence that the decoupling mechanisms had an impact as a driver (either positive or negative) on Conservation Achievement. However, we find that decoupling is important in removing barriers to Conservation Achievement.*[73]

Decoupling and Conservation Achievement (Totals): Perspective

Electric conservation is primarily influenced by the I-937 Energy Independence Act[74], rather than by decoupling, but decoupling does have an important role in removing barriers to Conservation Achievement. The role of the decoupling factor is to eliminate a financial disincentive so that other factors may operate as drivers; but it does not drive conservation programs.

Beyond the current I-937 Energy Independence Act conservation effort, Avista is a national leader in Smart Cities[75], Distributed Energy Resources (DER) and microgrid development[76]. These are major efforts that go beyond decoupling. The future is likely a combination (yet unnamed) of DSM, DERs, Smart Cities, an ecology of microgrids and nanogrids, and likely also integrates elements of climate adaptation.

Business Planning: Electric and Natural Gas 2012-2017

For perspective, we drop back in time, prior to the current decoupling because Avista has a deep history in DSM planning. For example, the Business Plan for 2012[77] notes that "Avista has

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[73] In response to DR 94, Avista states: "With or without Decoupling, Avista will make any necessary investments required in order to ensure high quality service for our customers. That said, decoupling positively effects how Avista now looks upon proliferation of distributed generation (net metering) in our system. Without decoupling, it is entirely reasonable to think from a regulatory and policy position, Avista would seek to minimize the amount of net metering on our system. With decoupling, that is not the case, similar to the goal of decoupling to remove any disincentive towards promoting energy conservation/efficiency." We do not disagree with this statement; however, we think that decoupling is important in removing barriers to Conservation Achievement.

[74] Washington, I-937: Utilities must pursue all conservation that is cost-effective, reliable and feasible. They need to identify the conservation potential over a 10-year period and set two-year targets. See: http://www.commerce.wa.gov/growing-the-economy/energy/energy-independence-act/. In response to DR 093, Avista states: "Avista does not feel that decoupling is a driver nor a barrier removal mechanism on conservation achievement. Given the requirements under the Energy Independence Act (EIA/I-937) to pursue all cost-effective, reliable, and feasible savings, that is the primary driver of conservation achievement."

[75] Data Response 043 (University District Smart City Accelerator Initiative).

[76] Data Response 044 (Micro-Transactive Grid). Avista has also done earlier work with microgrids and is viewed in the industry as a leader.

[77] Response to Data Request 016 (Annual DSM Plans), 2012 DSM "Revised" Business Plan, Avista Utilities, Revised December 7, 2011.

continually been providing energy efficiency programs, uninterrupted, since November 1st, 1978." That is forty (40) years of DSM planning and program implementation if we count the current year (2018). The 2012 Business Plan goes on to say: "[t]he Company's planning process builds on previous years experiences and addresses a number of challenges in regard to achieving energy acquisition targets, meeting cost-effectiveness criteria and satisfying regulatory reporting requirements."[78] Avista has substantial depth in DSM planning and program operation, as well as experience with evolving legislative and Commission targets that orient and drive the DSM planning function. Against this deep background, decoupling affects the current context in which conservation takes place. However, decoupling does not drive Conservation Achievement. Rather, the annual DSM plans are technical documents informed by technical concerns and directives to develop energy savings targets. The 2012 through 2014 plans are not influenced by decoupling (which began in 2015).

> As part of the pending General Rate Case Settlement Agreement in Docket Nos. UE-140188 and UG-140189, the Company agreed, in consideration for receiving a full electric decoupling mechanism, to increase its electric energy conservation achievement by 5% over the conservation target approved by the Commission, beginning with the 2014-2015 biennial target. The scope of the DSM Business Plan covers the majority of the acquisition eligible to achieve this target but does not include efficiencies achieved through distribution or generation facilities. Since the planning process has led to the expectation that the acquisition target will be achieved, the Company has not designed, and is not currently considering any contingency programs to increase acquisition to meet the target.

Figure 6-2. Planning for Decoupling 5%

Beginning with the 2012 Business Plan (completed in 2011) and moving forward, the first mention of decoupling occurs in the Business Plan for 2015 (Figure 6-2).[79] Here, the electric planning targets contain the five percent (5%) adder to DSM energy savings which is a part of the decoupling order. Since the electric adder was already covered within the flexibility of the planning process, no action was required to specifically further consider or address decoupling. There is no indication of any other influence of decoupling on planning for conservation achievement in the 2015 plan.

There are similar mentions of decoupling in the 2016 plan[80] and the 2017 electric plan[81]. While each plan is a comprehensive document, usually of 150 or more pages, there are no further

[78] Ibid., Executive Summary, P. 2.
[79] Response to Data Request 016 (Annual DSM Plans), Avista Utilities Washington/Idaho 2015 Demand-Side Management Business Plan, October 31, 2014, P. 9. Of course, the addition of the five-percent (5%) itself is an effect of decoupling. It was added and agreed to part of the decoupling agreement. At the policy/management levels decoupling had this influence on the DSM Plan that drives conservation. However, Task 6 directs that this addition to Conservation Achievement planning and accomplishment not be included in the analysis in this Section of the evaluation. We note it here for completeness.
[80] Response to Data Request 016 (Annual DSM Plans), Avista Utilities Washington/Idaho 2016 Demand-Side Management Business Plan, October 26, 2015, P7 & P, 8.
[81] Response to Data Request 016 (Annual DSM Plans), Avista Utilities Washington/Idaho 2017 Electric Demand-Side Management Annual Conservation Plan, November 15, 2016, P. 6 & P. 23.

substantive considerations of decoupling in any of the plans for 2015 through 2017. Similarly, there are no mentions of decoupling in the plans from 2012 through 2017 for natural gas.

We conclude from the analysis of Business Plans and Evaluations for 2012 through 2017 that decoupling had no independent effect on electric or natural gas planning beyond the 5% adder. Next, we examine Conservation Achievement directly in the series of Avista evaluations.

Total Conservation Achievement: Electric and Natural Gas: 2012-2017

To assess the role of decoupling in Conservation Achievement, we examine the Annual Conservation Reports & Cost Effectiveness Analyses for Washington for 2012 through 2017.[82] The Annual Conservation Reports & Cost Effectiveness Analyses report electric and natural gas conservation achievement against planning target goals. The Biennial Conservation Plan (BCP) for Washington's Energy Independence Act (Initiative 937 or I-937) provided energy savings targets for 2014 through 2015.

- In the 2014-2015 Biennium, Avista acquired 70,959 MWh (verified gross savings) in Washington or 104% of its two-year electric target of 68,204 MWh.[83] The five-percent (5%) decoupling adder did not apply in this Biennium.
- In 2016, Avista acquired 71,572 MWh (I-937 total adjusted reported gross savings) in Washington, or 130% percent of its I-937 target of 54,978 MWh.[84] The five-percent (5%) decoupling adder is included.
- In 2016-17, Avista acquired 139,450 MWh (total verified gross savings) in Washington, or 183% percent of its I-937 target of 141,331 MWh. The five-percent (5%) decoupling adder is included.[85]

With exceptionally high achievement levels for 2015-2017, the five percent (5%) conservation achievement for decoupling was easily surpassed.[86] The Annual Conservation Reports & Cost Effectiveness Analyses for 2012 through 2017 contain no further mention or analysis of decoupling. There are no mentions of decoupling from 2012 through 2017 for natural gas. *We conclude from the analysis of the Annual Conservation & Cost Effectiveness Reports for 2012 through 2017 that at the level of total achievement, decoupling had no independent effect on driving overall electric conservation achievement.* The substantial increase in performance for residential, low-income and non-residential from 2015 to 2016 is attributed "…to the increasing popularity of LED light, TLED lighting and Fuel Conversions."[87] This finding was repeated in the 2017 evaluation.[88]

[82] Responses to Data Requests 017, 018 and 070 (Annual Conservation Reports and Cost Effectiveness for 2012 through 2017).
[83] Washington 2015 Annual Conservation Report (ACR) & Cost-Effectiveness Analysis, May 31, 2016, P. 4.
[84] Washington 2016 DSM Annual Conservation Report & Cost Effectiveness Analysis, June 1, 2017, P. 18.
[85] These results have been updated to correct an error using numbers provided verbally by Avista during the report presentation/review meeting. Numbers reported here are slightly less than those in the Washington 2017 Annual Conservation Report & Cost-Effectiveness Analysis, June 1, 2018, Executive Summary, P. 1.
[86] Washington 2017 DSM Annual Conservation Report & Cost-Effectiveness Analysis, June 1, 2018, P. 17.
[87] Washington 2016 DSM Annual Conservation Report & Cost-Effectiveness Analysis, June 1, 2017, P. 7,
[88] Washington 2017 DSM Annual Conservation Report & Cost-Effectiveness Analysis, June 1, 2018, P. 6.

Also, "[a]t the start of 2017, the Washington electric tariff rider was underfunded by $8,283,048."[89] "The primary driver for the underfunded balance was the unanticipated high participation in the non-residential lighting program in 2017."[90] Similarly, for natural gas the tariff rider balance was underfunded by $1,410,964 at the start of 2017 and there was an underfunded balance of $626,653 at year-end.[91] These budget figures illustrate the positive operation of decoupling. Decoupling is not a driver for energy conservation. *But it facilitates pursuit of all cost-effective energy conservation in accord with Commission direction.* Anyone who has been present in a non-decoupled utility when a planned program budget cap is reached has heard staff telling customers that the budget cap has been reached, so they should consider tracking when the program will reopen in the next year and get their application in immediately. From experience, we have seen major programs (elsewhere) that are open for applications for one or two days a year. With decoupling, that barrier is removed; so, programs can follow the direction of I-937 to pursue all cost-effective conservation.

Residential Electric Group

As shown in the accompanying graph (Figure 6-3), residential electric conservation achievement dips in 2015 (as decoupling starts, but before decoupling has any effect on customer bills), jumps in 2016 (which has negligible bill effect from decoupling) and dips back to the 2014 pre-decoupling level in 2017 (the first full year subject to the decoupling adder each month). However, the reasons for these changes have little or nothing to do with decoupling.

For 2013, a major concern in planning was how to deal with the Washington I-937 Standards for the 2014-2015 Biennium.[92] For example, an agreement was reached holding that the unit energy savings used by the third-party completing Avista's CPA (used to establish the I-937 target) will remain fixed for the duration of that biennium, and there was a resolution of the problem of different market forecasting methods used by NEEA, reducing uncertainty for the Company. There were no major changes to residential electric programs. Decoupling was not mentioned in analysis or presentation.

In the 2015 Business Plan, Avista noted that "…falling avoided costs permeate throughout all phases of DSM operations and will require considerable innovation and flexibility in order to continue to deliver value to the customer."[93]

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[89] Ibid., P. 4.
[90] Ibid., P. 4.
[91] Ibid., P. 4.
[92] Avista Utilities Washington/Idaho 2014 Demand-Side Management Business Plan, November 1, 2013, Pp. 14-18.
[93] Avista Utilities Washington/Idaho 2015 Demand-Side Management Business Plan, October 31, 2014, P. 4.

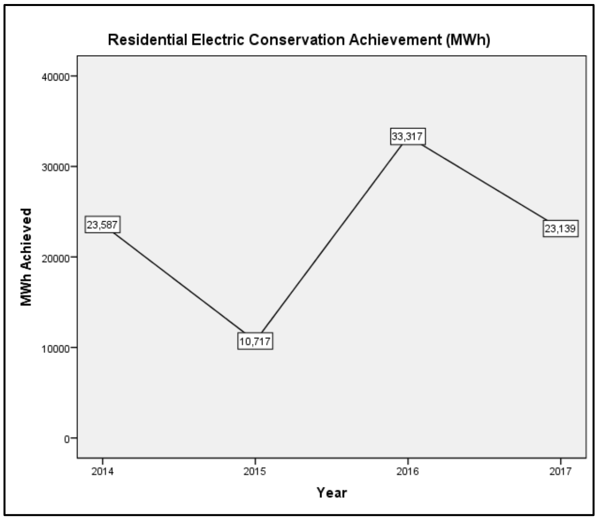

Figure 6-3. Conservation Achievement - Residential Electric

Further, the bundling of measures into programs was creatively optimized as follows. "The Company provides the highest possible value for the cost-effectiveness metric applicable to each program, maximizing the residual benefits (benefits less costs) of the applicable metric.

This choice plays an important role in the Company's planning process and the development of the final portfolio in three ways:[94]

1. By maximizing the portfolio residual benefits the Company will seek to add measures and programs to the extent that the incremental benefits of that resource option exceed the incremental cost. This approach precludes the rejection of measures or programs that favorably contribute to the cost-effectiveness of the portfolio but are not able to bear the non-incremental infrastructure cost that would be assigned to the program.
2. By only burdening measures and programs with the costs that are incremental to them at each level of aggregation, the potential for a 'death spiral' is reduced. If each measure were required to bear their fully allocated (including non-incremental) costs, incrementally cost-effective measures would potentially fail and, by being excluded from the portfolio, increase the non-incremental cost allocation to be borne by other measures.
3. In comparison to simply establishing a benefit-to-cost ratio in excess of 1.00 as a target, Avista's chosen approach leads to a larger portfolio as well as one which has higher residual benefits. It does this by providing a means for accepting cost-effective but marginal measures and programs that favorably contribute to the portfolio's residual benefits but may reduce the overall portfolio benefit-to-cost ratio."

Residential program and approaches were continued from the prior year. All analysis and discussion for 2015 was based on policy approaches and technical considerations. Decoupling

[94] Avista Utilities Washington/Idaho 2015 Demand-Side Management Business Plan, October 31, 2014, P. 7.

was not mentioned in analysis or presentation.[95] Similarly, discussion followed technical and policy approaches. Decoupling was not discussed in the 2016 plan,[96] or the 2017 plan.[97]

Low-Income Electric Group

As shown in Figure 6-4, low-income electric conservation achievement rises slightly from 2014 to 2015 (as decoupling starts, but before decoupling has any effect on customer bills), jumps in 2016 (which has negligible bill effect from decoupling) and dips back to slightly below the 2014 pre-decoupling level in 2017 (the first full year subject to the decoupling adder each month). However, the reasons for these changes have to do with program realities rather than with decoupling.

Avista uses a system of pre-approved measures to facilitate low-income weatherization work by the implementation agencies. Avista also notes that "CAP agencies individually prioritize and treat their clients based upon a number of characteristics. Several of the characteristics used to prioritize clients are related to resource cost-effectiveness, but cost-effectiveness based specifically upon the TRC or UCT test is not an explicit priority for the CAP agency."[98] There were no major changes in electric low-income programs. Decoupling was not mentioned in analysis or presentation for 2014.

For 2015, the approach to implementation of low-income weatherization was continued from 2014, with the same budget commitment. Decoupling was not mentioned in the analysis or presentation of Annual Conservation Plans for 2014, 2015, 2016 or 2017. For 2017, Avista notes openness to working towards a waiver for low-income electric customers like the waiver in effect for low-income natural gas customers.[99]

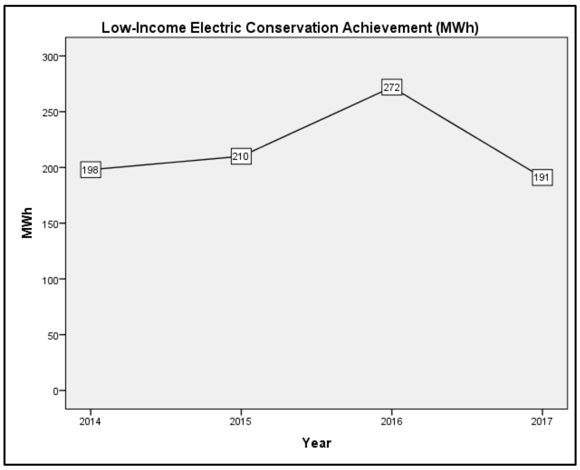

Figure 6-4. Conservation Achievement - Low-Income Electric

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[95] Avista Utilities Washington/Idaho 2015 Demand-Side Management Business Plan, October 31, 2014, P. 10.
[96] Avista Utilities Washington/Idaho 2016 Demand-Side Management Business Plan, October 26, 2015, Pp. 9-10.
[97] Avista Utilities Washington 2017 Electric Demand-Side Management Annual Conservation Plan, November 15, 2015, Pp. 7-8.
[98] Avista Utilities Washington/Idaho 2014 Demand-Side Management Business Plan, November 1, 2013, P. 19.
[99] Avista Utilities Washington 2017 Electric Demand-Side Management Annual Conservation Plan, November 15, 2016, P. 10.

Nonresidential Electric Group

As shown in Figure 6-5, Nonresidential electric conservation achievement rises slightly in 2015 (as decoupling starts, but before decoupling has any effect on customer bills), jumps in 2016 (which has negligible bill effect from decoupling) and then rises further in 2017 (the first full year subject to the decoupling adder each month). However, the reasons for these changes have to do with I-937 planning and program-level realities, rather than decoupling.[100]

Avista provides both prescriptive and site-specific programs (which may be proposed by the customer). Two improvements were:

- Revisions to the site-specific program implementation processes to improve clarity and promote the timely movement of projects through the pipeline.
- The establishment of two checklists (or "Top Sheets"), one prior to contracting and one prior to the payment of the incentive, in order to ensure consistent documentation and treatment of each project as it progresses through these processes towards completion.

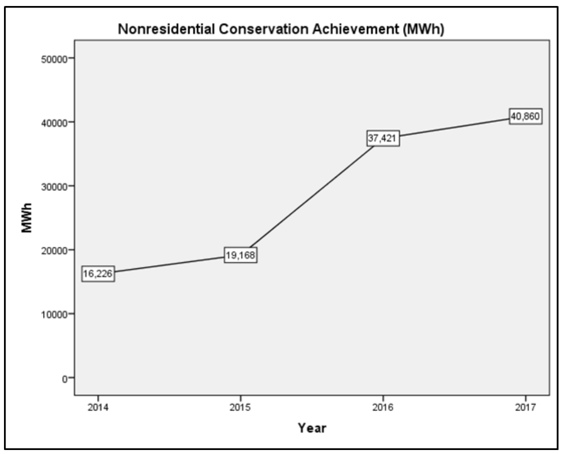

Figure 6-5. Nonresidential Electric Conservation Achievement (MWh)

There were also three changes to Washington Schedule 90, affecting electric programs:

- Shift the maximum energy simple payback for incentive eligibility from eight years to thirteen years for lighting measures with independently verified lives of 40,000 hours or more (e.g. LED lighting).
- Increase the maximum incentive from 50% of customer incremental cost to 70% of customer incremental cost for (1) typical lighting measures (those with lives under 40,000 hours) with energy simple paybacks under three years and (2) all other measures with energy simple paybacks less than five years.
- Clarification regarding how incentive caps apply to prescriptive measure applications.

Otherwise, non-residential electric programs for 2014 continued as in the prior years and marketing continued to be based primarily on an account manager approach. There were no major changes in electric non-residential programs. Decoupling was not mentioned in analysis or presentation for 2014.

[100] Avista Utilities Washington/Idaho 2014-2017 Demand-Side Management Business Plans.

For 2015, the 2014 program was continued with some technical adjustments. Decoupling was not mentioned in the analysis or presentation for 2015,[101] 2016,[102] or 2017.[103]

Residential Natural Gas Group

Leading up to the planning study and following direction from the Commission, Avista was continuing the Washington natural gas portfolio under a gross Utility Cost Test (UCT) metric rather than the previously applied net TRC. This was the first time that the Company employed the UCT test as the primary metric for optimizing portfolio performance.[104] This switch to the UCT has its source in the fall in the commodity cost of natural gas due to extensive fracking in the US[105]. Successful technological improvements in fracking have caused avoided cost to fall dramatically. This change has also meaningfully lowered the cost-effectiveness of much natural gas DSM,[106] with some carryover to electric DSM. Since residential natural gas programs were resumed using the UCT test, these programs were evolved to meet the UCT test and continued.

As shown in Figure 6-6, residential natural gas Conservation Achievement dropped from 2014 to 2015, then rose in 2016 and rose again in 2017 (the first year in which customers experienced the decoupling bill adder each month). However, the reasons for these changes have to do with program realities, rather than with decoupling. Decoupling was not mentioned in analysis or presentation for 2014. Residential natural gas programs continued from 2014 through 2015, 2016 and 2017,[107] again with no mention of decoupling in either analysis or presentation.

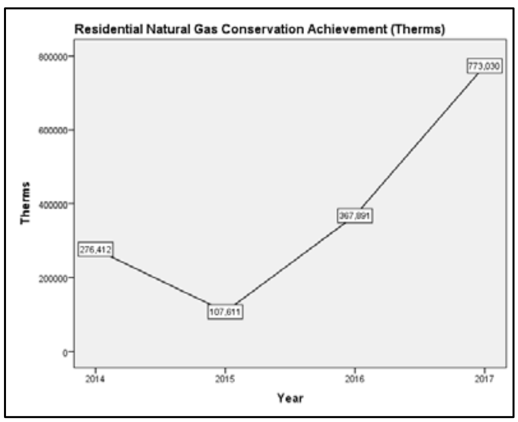

Figure 6-6. Residential Natural Gas Conservation Achievement

[101] Avista Utilities Washington/Idaho 2015 Demand-Side Management Business Plan, October 31, 2014, Pp. 12-14.
[102] Avista Utilities Washington/Idaho 2016 Demand-Side Management Business Plan, October 26, 2015, Pp. 11-12.
[103] Avista Utilities Washington 2017 Electric Demand-Side Management Annual Conservation Plan, November 15, 2016, Pp. 7-8.
[104] Avista Utilities Washington/Idaho 2014 Demand-Side Management Business Plan, November 1, 2013, P. 4.
[105] Estimate of the percentage of regional US natural gas that is fracked range from about 50% to 70%, depending on region. The cost reduction caused by fracking is estimated to be from about $180 to $430 per residential customer per year. This is the equivalent of a very substantial customer discount program and it applies to all customers, not only low-income households.
[106] It also translated into lower avoided cost for electricity from natural gas generation, but generally electric measures remained cost-effective.
[107] Avista Utilities Washington 2017 Gas Demand-Side Management Annual Conservation Plan, November 15, 2016, Pp. 5-7.

Low-Income Natural Gas Group

The low-income programs are special since though they are referenced to cost-effectiveness, it is understood that low-income customers are not able to receive weatherization services unless the cost is fully paid by the utility or other transfer such as federal and state funding and voluntary contributions. Low-income weatherization is substantially supplemented by state and federal funding. As with electric low-income weatherization, "CAP agencies individually prioritize and treat their clients based upon a number of characteristics. Several of the characteristics used to prioritize clients are related to resource cost-effectiveness, but cost-effectiveness based specifically upon the TRC or UCT test is not an explicit priority for the CAP agency."[108] Federal and state policy substantially guides low-income weatherization.

As shown in Figure 6-7, low-income Conservation Achievement dipped from 2014 to 2015, then increased dramatically in 2016 and dropped to below the pre-decoupling 2014 level in 2017. These changes were not driven by decoupling. Decoupling was not mentioned in analysis or presentation in 2014, 2015, 2016 or 2017 DSM Annual Conservation Report & Cost Effectiveness Analyses. In 2017, natural gas low-income programs operated using a waiver system for natural gas measures that permits full-funding of those measures.[109,110]

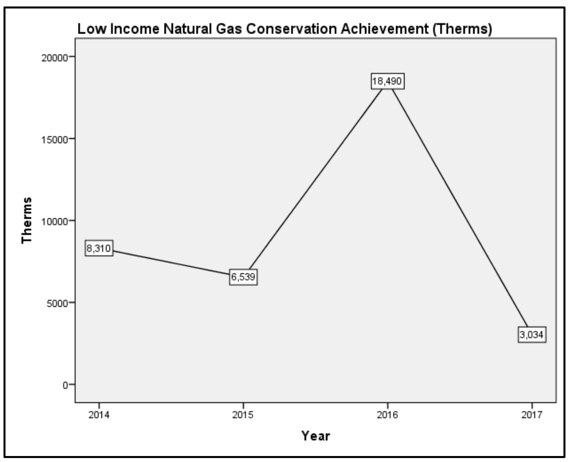

Figure 6-7. Low-Income Natural Gas Conservation Achievement

For low-income customers, "[t]he list of measures offered is derived from the Department of Commerce's Weatherization Manual. To guide the agency toward projects that are most beneficial for the Company's energy efficiency efforts, in most cases an "Approved" list of measures is provided that allows for full reimbursement of those that in most cases have a Total Resource Cost (TRC) of 1 or better. For efficiency measures with a TRC less than 1, a "Rebate"

[108] Avista Utilities Washington/Idaho 2014 Demand-Side Management Business Plan, November 1, 2013, P. 19.
[109] Avista Utilities Washington 2017 Electric Demand-Side Management Annual Conservation Plan, November 15, 2016, P. 10.
[110] Avista Utilities Washington 2017 Gas Demand-Side Management Annual Conservation Plan, November 15, 2016, P. 8.

that is equal to the Company's avoided cost of energy is provided as the reimbursement to the Agency."[111]

Nonresidential Natural Gas Group

Nonresidential natural gas Conservation Achievement (Figure 6-8) rises dramatically from 2014 to 2015 (as decoupling starts, but before decoupling has any effect on customer bills. Then achievement drops dramatically from 2015 to 2016 (which has negligible bill effect from decoupling). Achievement then from 2016 to 2017, reaching to a point just above the 2014 (pre-decoupling) level in 2017 (the first full year with the decoupling adder).

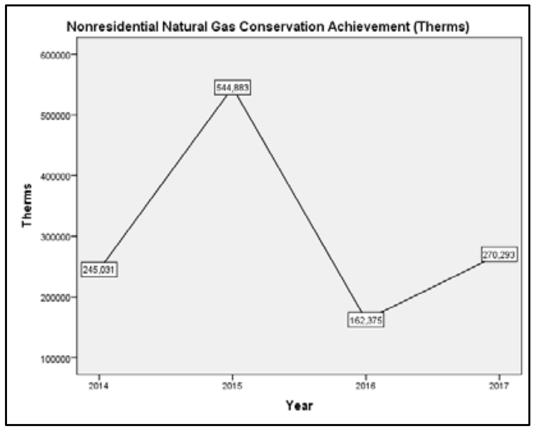

Figure 6-8. Nonresidential Natural Gas Conservation Achievement

Schedule 190 (natural gas efficiency, Washington only) was modified as follows:[112]

- Decrease the incentives of each of the incentive tiers by approximately 1/3rd due to the decrease in avoided costs.
- Eliminate the maximum energy simple payback of thirteen years for incentive eligibility.
- Clarification regarding how incentive caps apply to prescriptive measure applications.

The revisions to the Washington Schedule 190 tariff were part of a larger interim planning process designed to optimize the natural gas DSM portfolio for improved performance against a gross UCT cost-effectiveness metric. Decoupling was not mentioned in the analysis or presentation in 2014, 2015, 2016 or 2017.[113]

Summary - Impact on Conservation Achievement

In this section of the evaluation, we have shown that decoupling was an important factor facilitating Conservation Achievement, but not a driver of Conservation Achievement. On the

[111] Avista Utilities Washington 2017 Gas Demand-Side Management Annual Conservation Plan, November 15, 2016, P. 8.
[112] Avista Utilities Washington/Idaho 2014 Demand-Side Management Business Plan, November 1, 2013, P. 23.
[113] Avista Washington 2014 Annual Conservation Report (ACR) & Cost-Effectiveness Analysis, May 29, 2015; Avista Washington 2015 Annual Conservation Report & Cost Effectiveness Analysis, May 31, 2016; Avista Washington 2016 DSM Annual Conservation Report & Cost-Effectiveness Analysis, June 1, 2017; Avista Utilities Washington 2017 Gas Demand-Side Management Annual Conservation Plan, November 15, 2016, Pp. 8-9.

electric side the I-937 ten-year plan was the primary driver. On the natural gas side, Commission direction towards use of the gross UCT test was a primary driver (in maintaining or expanding programs that were not cost-effective using the net TRC test). On both the electric and natural gas sides, the size of the signal from decoupling was too small to be of meaningful impact on Conservation Achievement, and, in any case, the signal is neutral.

Considered subjectively, these decoupling signals were even smaller because so many other programmatic and policy efforts occurred at the same time. Also, the price signals were mixed as to sign (plus or minus). It comes down to the fact that decoupling is known to be a way to remove the "throughput" barrier to energy conservation, but not as a stimulus to energy conservation. The removal of a barrier does not in itself provide a "pull" towards energy efficiency. Based on this analysis, we conclude that there is no evidence that decoupling has any meaningful impact as a driver for energy Conservation Achievement. However, in the presence of a strong driver like I-937 or a strong driver like Commission direction to use the gross UCT test, it provides revenue stability and more timely revenue recovery and so is a part of a "package" in that it eliminates the "throughput" incentive. Decoupling comes in when a program is exceeding its planning target, sometimes by a large amount. Where a non-decoupled utility will turn away energy conservation customers, having reached its budget cap, Avista has demonstrated that a decoupled utility can keep on servicing to acquire all cost-effective energy conservation.[114] This is also the perspective of the Regulatory Assistance Project (Figure 6-9).[115]

> Decoupling eliminates a strong disincentive to invest in energy efficiency. By itself, however, decoupling does not provide the utility with a positive incentive to invest in energy efficiency or other customer-sited resources, but it does remove the utility's natural antagonism to such resources due to their adverse impact on short-run profits.

Figure 6-9. Regulatory Assistance Project on Decoupling

We should note as a qualification that our conclusions are based on analysis of fourteen months of application of the decoupling adjustments (Schedules 75 and 175) on customer bills, for the last two months of calendar 2016 and calendar year 2017. It is possible that long-run impacts might be different. There is also a lagged impact on decoupling revenue from conservation achievements that leads to higher decoupling revenue collected from the rate group achieving the savings. Essentially what current program participants in a rate group do not pay toward fixed costs through volumetric charges is collected from everyone else in the rate group through future decoupling revenues. Conservation savings cumulate until a rate case resets the test year

[114] Another benefit of decoupling is illustrated in comparison to the alternative of assigning all variable costs to variable charges and all fixed costs to fixed charges. This alternative would require a large, non-bypassable fixed fee each month and result in a low volumetric charge. This would create difficult economics for low and moderate-income customers and very efficient customers. It would raise strong barriers to the dollar value of conservation to customers when it comes to the "please pay" amount on customer bills. Again, however, this is an instance of decoupling removing barriers to energy conservation. It is not a case of decoupling acting as a driver to stimulate energy conservation.

[115] Regulatory Assistance Project, Revenue Regulation and Decoupling, A Guide to Theory and Application. Second Printing, November 2016 (https://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decoupling-guide-second-printing-2016-november.pdf).

incorporating recent program savings into the new base. This is true regardless of the prevailing decoupling rate at the time of conservation savings. Electric to natural gas conversions result, with a lag, in higher electric decoupling revenue to recover fixed electric system costs that conversion participants are no longer paying and lower natural gas decoupling revenue to refund the over collection of natural gas system fixed cost by the same conversion participants.

Section 7. Analysis of Possible Adverse Impacts

Decoupling is a purposive reform designed "…to ensure that utilities have a reasonable opportunity to earn the same revenues that they would under conventional regulation, independent of changes in sales volume."[116] An optimal decoupling mechanism would achieve revenue neutrality while removing the inherent management and organizational drive to increase energy sales ("the throughput incentive").

Sometimes, purposive programs have unintended side effects. Here we focus on possible adverse impacts caused by or associated with decoupling (Figure 7-1).

Task 7: Analysis of Possible Adverse Impacts

Identification of any conclusive evidence to suggest that the Mechanisms adversely impacted customer service, distorted price signals for customers resulting in lower participation in conservation programs, or eroded Avista's incentive to control costs and improve efficiency and/or Washington required service quality measures.

Figure 7-1. Identify Adverse Impacts

Are there Adverse Effects?

Both formal learning and lessons of experience teach us that any rationally designed and purposive program may develop unanticipated side effects.[117] No matter how skilled the development, or the degree of integrity and insight from which a program springs, or the ability of policy reform to achieve intended results in actual practice, any reform may have unanticipated and unintended consequences.[118] The high-level question in this section of the evaluation is to determine if there is any conclusive evidence to suggest that the Mechanisms adversely impacted Avista's customer service, created price signals that lowered participation in

[116] Lazar, Jim, "Examples of Good, Bad, and Ugly Decoupling Mechanisms", presentation to NARUC Symposium: Aligning Regulatory Incentives with Demand-Side Resources. San Francisco, California August 2, 2006 (https://pubs.naruc.org/pub.cfm?id=4AC7A83F-2354-D714-5130-4C68971713CB).

[117] Although the recognition of unintended/unanticipated consequences is currently attributed to Merton, Merton himself notes a deep historic chain of prior writers: "In some one of its numerous forms, the problem of the unanticipated consequences of purposive action has been treated by virtually every substantial contributor to the history of social thought." See: Merton, Robert K, "The Unanticipated Consequences of Purposive Social Action," *American Sociological Review*, Vol. 1, No. 6 (December., 1936), pp. 894-904. Beyond this, by observation, intelligent animals experience unanticipated consequences, so it is quite likely that, being a phenomenon observed in animals, experiential recognition of unintended consequences is older than human history. This observation of the historically deep experience of unanticipated consequences fits with the Darwinian model for both biological and social evolution.

[118] Following Donald Campbell, the terms "program" and "reform" are used interchangeably: a new approach or program, such as decoupling – a policy reform effected in governance and institutional practice is both a program and a reform.

conservation programs, or eroded Avista's incentive to control costs and improve efficiency and/or Washington required service quality measures.[119]

Following the research questions for this evaluation, we focus on three sub-areas:

- Did decoupling impact Avista's service quality, on the Washington required service quality measures?
- Were there decoupling price signals that resulted in lower participation in conservation programs?
- Did decoupling erode Avista's incentive to control costs and improve efficiency?

Customer Service and Service Quality Indices (SQI)

Avista implements the State of Washington required Service Quality Indices (SQI) and reliability measures.[120] The existence of this series of yearly reports permits examination of customer service metrics to see if service goals have been met since the beginning of decoupling in 2015 and/or since the first impact of decoupling on energy bills in November 2016.

First, we examine Avista Service Quality Indices following decoupling to see if service goals were met, keeping in mind that calendar 2017 is the only year fully within the "after decoupling" time window from a customer perspective. As shown in the tables for 2015, 2016 and 2017 service goals were achieved each year. *There were no negative effects on these SQI indicators.*

We may also note that there were no positive effects on the SQI indicators. For example, "Percent of customers satisfied with our Contact Center services, based on survey results" was about 96% for 2015, 93% for 2016 and 94% for 2016, so within a band of 3%. The complex nature of the formation of indicator values in terms of context (for example, weather) and human behavior suggests that as a methodological rule, key performance indicators (KPIs) not be over-interpreted. We expect yearly results on each KPI to dance around from year to year within a reasonably judgmentally assessed neutral bandwidth without the size or direction of differences conveying meaning. A sense for defining a "neutral band" is developed from practical experience.

Conceptually this "neutral band" is made up of movements in indicators that result from a very large mix of small influences from a large range of factors including both proximate and remote influences. In addition, many of the active factors are likely random. So, performance tables like Table 7-1 through Table 7-7 usually cannot be used to analyze these small differences (positive or negative).

Though not useful for assessing small differences, KPIs provide a powerful tool so that regulators can monitor a utility's performance. The primary use of the KPIs is to make achievement of regulatory goals explicit. This is shown, using check boxes in the final columns

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[119] Sometimes side effects may be anticipated by some parties while the preponderance of parties involved in shaping, managing and implementing a program may not see a side effect, except retrospectively. In such a case we might say, retrospectively, that the effect was "hidden in plain sight".

[120] The Washington required Service Quality Indices are provided by Avista in response to H. Gil Peach & Associates LLC Data Request No. 52.

of Table 7-1 through Table 7-3. Where there has been a regulatory reform such as decoupling, a secondary use of KPIs is in review to determine if there has been a correlated systematic structure of change in KPI results (either a directionally consistent string of positive or negative results by year (regardless of size) or a directionally consistent string of large positive or negative results by year). While for decoupling the primary question concerns possible adverse effects, results might be positive as well as negative.

If either a directionally consistent string of small changes or a directionally consistent string of large changes is found, then the question shifts from correlation to possible causation. For example, in Washington it would not be unusual to find that severe weather events or severe weather patterns is the primary cause for change in KPI results. Also, we have sometimes found that when customer contact or services are outsourced, change can be due to performance of a particular service vendor or replacement by a different service vendor.

We find no directionally consistent string of either small or large changes in this analysis. There are no meaningful patterns evident in these tables of this section of the study (Section 7). Performance is high and consistently high. There are no meaningful negative or positive effects on any of the Section 7 KPIs.

Table 7-1. 2015 Indicators of Customer Service Quality – DR 52

Customer Service Measures	Benchmark	2015 Performance	Achieved
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	96.1%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	96.8%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.17	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	80.7%*	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	44 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies, per year	No more than 55 minutes	51 Minutes	✓

* Results for 2015 on percent of calls answered live within 60 seconds by the Avista Contact Center include all calls received for the year, including the nearly 56,000 calls answered during the November Wind Storm event from November 17 through November 27, 2015.

Table 7-2. 2016 Indicators of Customer Service Quality – DR 52

Customer Service Measures	Benchmark	2016 Performance	Achieved
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	92.7%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	94.7%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.25	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	81.7%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	39.3 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies, per year	No more than 55 minutes	48.4 Minutes	✓

Table 7-3. 2017 Indicators of Customer Service Quality – DR 52

Customer Service Measures	Benchmark	2017 Performance	Achieved
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	93.6%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	95.2%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.16	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	81.5%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	39.9 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies, per year	No more than 55 minutes	50.29 Minutes	✓

Next, as shown in Table 7-4, for customer service measures that were collected both before and after decoupling, there is no change in the perceived level of customer service by customers. Given the very small fluctuations in year-to-year, these results are stable from 2012 through 2017. There were no negative effects on these "before and after" SQI indicators.

Table 7-4. Customer Service Indicators for Before and After Decoupling – DR 52

Customer Service Measure	2012	2013	2014	2015	2016	2017
Percent Satisfied with Contact Center Services	93.1%	94.1%	94.9%	96.1%	92.7%	93.6%
Percent Satisfied with Field Services	93.3%	95.2%	94.4%	96.8%	94.7%	95.2%
Percent Calls Answered in 60 Seconds	83.7%	82.8%	82.9%	80.7%	81.7%	81.5%
Note: Percent Satisfied includes customers who were either "satisfied" or "very satisfied" with their service.						
Note: Results for 2015 on percent of calls answered live within 60 seconds by the Avista Contact Center include all calls received for the year, including the nearly 56,000 calls answered during the November Wind Storm event from November 17 through November 27, 2015.						

For electrical reliability (Table 7-5) two measures are reported. The System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI). SAIFI indicates the frequency of long-term (greater than five minutes) service interruptions. Reliability improves as SAIFI becomes smaller. The System Average Interruption Duration Index (SAIDI) measures the duration of long-term (greater than five minutes) service interruptions. Reliability improves as SAIDI becomes smaller. As shown in Table 7-5, values of SAIFI and SAIDI change from year to year. The highest values for both occur in 2017, the first full post decoupling year. However, this fluctuation does not provide conclusive evidence of a meaningful change. One would need to see a pattern (beginning with the values of the 2017 indicators) that continues for more years before drawing a systematic conclusion (negative or positive).[121] For electric reliability, there is no conclusive evidence of an adverse effect.

[121] Also, one would need to see if there is an explanation for the fluctuation in sources other than decoupling, such as weather. Avista, in response to Data Request 080, fills out the contextual background needed to more fully understand fluctuation in SAIFI and SAIDI (emphasis in italic added): "As noted on pages 53-57 of Avista's Customer Service Quality and Electric System Reliability report for 2017, *approximately two-thirds of the utility's system performance each year is subject to random forces such as weather patterns and storms, or other random events such as an outage caused by a car striking a pole, which factors are generally beyond the control of the utility. Consequently, there is a natural variation in results (both up and down) from year to year, due largely to the interaction of these random factors. The "direction" of the annual results and the magnitude of the variation generally reflects the combination of the frequency and magnitude of weather-related events, the contribution of other randomly-occurring factors*, as well as the effect of standardized adjustments made to the yearly results based on "major event days" (please see footnote 47 on page 54 of the above-mentioned Service Quality and Reliability report for 2017). As an illustration of these principles in action, Avista's SAIFI score for 2016 was the lowest value recorded since our 2005 baseline year, while the 2017 result was the fifth highest recorded over the same period. Likewise, the annual score for SAIDI in 2016 was the third lowest measured since 2005, while the value for 2017 was the second highest measured over the same period of time. *Generally, the results for 2017 reflect the greater storm activity we experienced compared with 2016, combined with the relatively small downward adjustment in the numbers based on minimal major events in 2017*." We accept this explanation for this evaluation.

Table 7-5. Indicators of Electric Service Reliability – DR 52

Electric Service Reliability Measure		2012	2013	2014	2015	2016	2017
SAIFI	System Average Interruption Frequency Index	1.14	1.05	1.11	1.05	0.86	1.20
SAIDI	System Average Interruption Duration Index	138	138	139	163	133	183
Note: The System Average Interruption Frequency Index or "SAIFI" is the average number of sustained interruptions (outages) per customer for the year.							
Note: The System Average Interruption Duration Index or "SAIDI" is the average duration of sustained interruptions (outages) per customer for the year (measured in minutes).							

Beginning January 1, 2016, Avista introduced a new set of indicators, which can also be considered a very visible tool to motivate staff with the Customer Service Guarantee to Washington customers.[122] There are seven specific performance guarantees. Missing the goal for performance on a guarantee will result in a payment of fifty dollars ($50) as a credit on the customer bill.[123] As shown in Table 7-6 and Table 7-7, Avista's performance on these new indicators is very good, with an error rate of about five out of a thousand (0.0053) for 2016 and of about two out of a thousand (0.0023) in 2017.

Taken together, these service quality results show no adverse impacts of decoupling on service quality. There are only two measurement years for these results and the values are so small relative to the number of customers that weather and small influences and random factors are likely to predominate in generating results. Several years of measurement or the occurrence of large effects in results would be needed to demonstrate correlation and then call for a search for causation. With the data that exists, there is no indication of adverse effect of decoupling on customer service.

[122] See: Response to Data Request 081 and: https://www.myavista.com/about-us/contact-us/customer-service-guarantees.

[123] Subject to conditions. There is no payment if a customer cancels or misses an appointment or if the Company reschedules an appointment with at least 24-hours' notice; or, if there is a major weather event that impacts a large number of customers or lasts for a longer period of time, such as a major snow, ice, or wind storm; or, if there is an action or default by someone other an Avista employee or outside of Avista's control; or, if construction is required before service can be energized, evidence that all required government inspections have been satisfied has not been received by Avista, required payments to Avista have not been received, or service has been disconnected for non-payment or there has been theft/diversion of electric service; or, when power is interrupted for less than five minutes, power is interrupted because of work on a meter, or the safety of the public or of Avista employees or the imminent failure of Avista equipment was a factor causing the interruption in service.

Table 7-6. 2016 Customer Service Guarantee - DR 52

Customer Service Guarantee	Successful	Missed	$ Paid
Keeping Our Electric and Natural Gas Service Appointments scheduled with our customers	1,477	10	$500
Restore service within 24 hours of a customer reporting an outage (excluding major storm events)	26,344	1	$50
Turn on power within a business day of receiving the request	3,380	3	$150
Provide a cost estimate for new electric or natural gas service within 10 business days of receiving the request	5,024	0	$0
Investigate and respond to a billing inquiry within 10 business days if unable to answer a question on first contact	1,760	0	$0
Investigate a reported meter problem or conduct a meter test and report the results within 20 business days	309	2	$100
Notify customers at least 24 hours in advance of a planned power outage lasting longer than 5 minutes	30,336	349	$17,450
Totals	**68,630**	**365**	**$18,250**

Table 7-7. 2017 Customer Service Guarantee - DR 52

Customer Service Guarantee	Successful	Missed	$ Paid
Keeping Our Electric and Natural Gas Service Appointments scheduled with our customers	1,584	11	$550
Restore service within 24 hours of a customer reporting an outage (excluding major storm events)	30,669	23	$1,150
Turn on power within a business day of receiving the request	9,557	0	$0
Provide a cost estimate for new electric or natural gas service within 10 business days of receiving the request	3,929	0	$0
Investigate and respond to a billing inquiry within 10 business days if unable to answer a question on first contact	1,623	0	$0
Investigate a reported meter problem or conduct a meter test and report the results within 20 business days	1,082	1	$50
Notify customers at least 24 hours in advance of a planned power outage lasting longer than 5 minutes	17,079	115	$5,750
Totals	**65,523**	**150**	**$7,500**

Price Signals and Conservation Participation

Decoupling does not change the overall amount of fixed cost to be recovered. It changes the timing of recovery and reduces volatility by recovering fixed cost not already recovered from volumetric charges. These amounts are recovered in small yearly increments.[124] Determination of the revenue requirement associated with fixed cost is a step in the process of developing a cost of service analysis. Cost of service analysis is a separate form of analysis that occurs independent of the form of recovery. The decoupling mechanism recovers fixed cost outside of volumetric rates annually and balances any under-recovery or over-recovery annually. In the absence of decoupling, the utility would either over or under recover its fixed costs.

With or without decoupling, once established as a revenue requirement, the established fixed cost is allocated to customer groups. Projected recovery involves construction of planning targets (projections based on experience). In decoupling, fixed costs are recovered in the volumetric charge (if energy usage matches planned energy usage); or if there is under-recovery, are set to be recovered through an adjustment in volumetric rates in the following rate year, subject to certain control tools, including the three-percent (3%) cap. Similarly, any over-recovery is refunded through a reduction in volumetric rates in the following rate year. The decoupling allocation of fixed costs for a customer group is based on the group's actual energy use in relation to the group's projected energy use.

Historically (and contrary to what might be expected from the term "fixed" cost), many fixed costs are recovered in volumetric revenue (cost per unit of energy). In Avista's decoupling, two separate time windows are used: a *measurement time window*, during which the data for decoupling adjustment for the next implementation time window is collected; and a *rate year*, an *implementation time window* in which the resulting rate adjustment is applied. In Avista's decoupling, the measurement time windows are calendar years. When, during a measurement window calendar year, a group decreases energy usage so that the average usage for the group is below the planning projection for that group for that year, the decoupling adjustment automatically makes up the lost revenue in the next rate year 12-month implementation window by requiring an increase in the group's volumetric cost per unit (cost per kWh or cost per therm). Conversely, if in a measurement time window calendar-year the average usage for a group exceeds the planning projection, the mechanism will require a reduction in unit cost for the next 12-month implementation time window (rate year).

Given the decoupling price signals observed, did decoupling price signals influence energy conservation effort?

Calendar 2015: The answer is "no" for 2015. While the first measurement window was calendar 2015, no decoupling amounts were billed to customers during 2015.

[124] The more frequent yearly rate effect with decoupling should sum to the (theoretical) less frequent aggregated rate recovery impact (without decoupling) over a set of rate cases.

Calendar 2016: The answer is "no" for 2016 because the signal was too small to influence changes in energy conservation. Any changes in energy conservation effort in 2016 would be due to other factors.

In fact, the rate impact of decoupling for the electric decoupled groups was negligible in 2016 (Table 7-8). The first 12-month implementation time window (rate year) ran from November 2016 through October 2017. As shown in the table, no decoupling amounts were billed from January through October 2016 so there could have been no influence for most of the year. Price signals were present only in November and December.

Since energy bills are sent using billing cycles (allocated throughout the days of a month) the price signal phased in across the month of November. The first price signal fully experienced by decoupled customers occurred in December 2016.

Further, response to a very small price signal usually occurs with a lag. If a response were beginning to be developed, it would not be detectable until 2017. Also, except for special cases, from experience December is not a likely month for focus on energy conservation projects.[125] Private life, vacation time, the holidays and the weather tend to envelop people in December. Institutional efforts tend to slow down, to return to vigor in January.

Table 7-8. Electric Decoupling Signal as Percentage of Average Bill for Calendar 2016

Group	Jan-Oct	Nov	Dec	Total (2016)
E1: Residential	0%	1.1%	2.8%	0.4%
E2A: General Services	0%	0.4%	-1.2%	-0.1%
E2B: Large General Services	0%	-0.6%	-1.5%	-0.2%
E2C: Pumping	0%	-0.4%	-1.3%	-0.1%

Table 7-9. Natural Gas Decoupling Signal as Percentage of Average Bill for Calendar 2016

Group	Jan-Oct	Nov	Dec	Total (2016)
G1: Residential	0%	1.2%	3.3%	0.6%
G2A: General Services	0%	1.3%	3.0%	0.5%
G2B: Large General Services	0%	1.4%	7.3%	-14.7%

Similarly, the rate impact of decoupling for the natural gas decoupled groups was also negligible in 2016 (Table 7-9). As with decoupled electric service, natural gas service provided no decoupling price signals until November 2016. As with decoupled electric service, the signal for decoupled natural gas service was phased in over the days of November due to billing cycles. As shown in the table, price signals for G1: Residential and for G2A General Services are negligible, so any changes in conservation effort in 2016 would be due to factors other than the price signal from decoupling. For G2B: Large General Services, there is an anomaly in the data due to a base problem that occurred in December (and continued through January 2017), so data from Table 7-9 cannot be used.

[125] An exception is auto plants which typically take advantage of holiday expectations to shut down for a week in December to implement physical changes in the plant.

Calendar 2017: The answer is also "no" for calendar 2017. Calendar 2017 is the first full year of customer experience with the decoupling price signals. But, for both electric and natural gas, the size of both monthly and yearly signals is small (Table 7-10 and Table 7-11). Likely, these changes would not be noticed. If small changes were to be noticed (positive or negative), drawing of conclusions or taking actions that might affect conservation would likely occur with a lag. If were to be an effect, it would not be expected in the first quarter of 2017; and likely not until the fourth quarter of 2017 or after.

As a customer strategy, it remains true that participation in conservation programs can substantially lower energy bills. Almost always, this will much more than offset a number of small rate increases over a number of years. A small rate increase or decrease does not have a signal strength to outbalance the cost advantage of using fewer units of energy. And, of course, the price signal from fixed cost will occur anyway, with or without decoupling. Only the timing would be different.

For 2016, the 3% cap came into play for the E1: Residential electric group, so there was a limit on the decoupling adder for 2016 and a deferral carryover to 2017. However, there was no deferral carryover from the 2017 rate year to the 2018 rate year. For natural gas, the 3% cap came into play for the G1: Residential electric group in 2016, creating a deferral carried over into 2017. For this group, there was also a cap for 2017 and a deferral carryover into 2018. However, the carryover into 2018 was small. Sustained or snowballing deferral can have an impact on GAAP accounting, which requires that revenues must be recovered within two years.[126] Avista refers to decoupling deferrals that go unreported in revenue due to GAAP accounting rules as contra-decoupling deferrals. Contra-decoupling deferrals were recorded for natural gas in both 2015 and 2016. What happens next depends on the weather. Through 2017, decoupling is operating as expected (as planned) and is not presenting price signals that would adversely affect conservation.

In summary, analysis of price signals and conservation shows no adverse effect from Avista's decoupling on energy conservation.

[126] In the Response to Data Request 064, Avista indicates ways in which the mechanism could be improved: "GAAP reporting rules do not allow for recognition of revenues from a mechanism like decoupling in excess of the amount expected to be recovered within 24 months of the end of the deferral period." One solution would be moving to a July 1 effective date for implementation of rate changes. Another would be "to make the mechanism more symmetrical so that in rebate years some benefit could be withheld to offset future surcharges. Please see the Company's response to Decoupling_DR_058 regarding the higher likelihood of surcharges than rebates due to continued energy efficiency implementation." We support the proposal for a July 1 effective date and exploration of seeking more symmetry.

Table 7-10. Electric Decoupling Signal as Percentage of Average Bill for Calendar 2017

Group	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total (2017)**
E1: Residential	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	3.5%	4.6%	3.0%
E2A: General Services	-1.2%	-1.2%	-1.2%	-1.2%	-1.1%	-1.2%	-1.2%	-1.2%	-1.2%	-1.1%	-0.6%	0.3%	-1.0%
E2B: Large General Services	-1.6%	-1.6%	-1.6%	-1.6%	-1.5%	-1.5%	-1.5%	-1.6%	-1.6%	-1.5%	-0.7%	0.4%	-1.3%
E2C: Pumping	-1.5%	-1.5%	-1.5%	-1.5%	-1.6%	-1.7%	-1.8%	-1.8%	-1.8%	-1.7%	-1.0%	0.2%	-1.7%

Table 7-11. Natural Gas Decoupling Signal as Percentage of Average Bill for Calendar 2017

Group	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total (2017)**
G1: Residential	3.3%	3.3%	3.3%	3.2%	3.0%	2.5%	2.1%	2.0%	2.1%	2.8%	4.5%	6.5%	3.7%
G2A: General Services	3.3%	3.2%	3.2%	3.1%	3.0%	2.9%	2.7%	2.7%	2.8%	3.0%	4.4%	6.1%	3.6%
G2B: Large General Services	3.7%	3.4%	3.3%	3.3%	3.3%	3.3%	3.2%	3.3%	3.3%	3.2%	4.5%	7.6%	3.7%

Cost Control and Operational Efficiency

We find no indication of any adverse effect of decoupling on the utility's incentive to control costs. Avista's perspective is that "[t]he adoption of decoupling has not resulted in a change of efforts by the Company to operate efficiently, rather the Company has, prior to decoupling, and with decoupling, strived to be as efficient as possible while at the same time providing safe and reliable service for our customers."[127] Further, the Company points out that "[t]he decoupling mechanisms provide recovery of fixed costs, on a revenue per customer basis, that were approved by the Commission in a prior general rate case for recovery. To the extent those fixed costs increase, or escalate, over time, the mechanisms do not provide for recovery of the change in costs above the approved level already embedded in the allowed revenue per customer. The Company continues to bear the risk of changes in costs between general rate cases, and therefore must (and has) manage the business in a prudent manner."[128]

By removing the focus on sales, decoupling may permit utility executive management to focus more effectively on other goals. Because cost recovery proceeds in a decoupled utility following a target revenue requirement that has already been projected in a commission proceeding, costs have been anticipated. A focus on cost control can function within this *already established revenue requirement* to improve earnings. This does not mean that current cost-control projects derive directly from decoupling. Avista has continually developed cost-control projects prior to decoupling. However, with decoupling, Avista cannot increase profits by increasing sales but can *only positively improve profits by improving cost control and operational efficiency*. The nature of this relationship under decoupling has been described by the Regulatory Assistance Project (Figure 7-2).

> Decoupling does not guarantee utilities a level of earnings, only an assurance of a level of revenue. If the utility reduces costs, it increases earnings, just as it would under traditional regulation. Also, because the utility cannot increase profits by increasing sales, improved operational efficiency is the only means by which it can boost profits.
>
> Source: The Regulatory Assistance Project, Revenue Regulation & Decoupling: A Guide to Theory and Application. Montpelier, Vermont: Regulatory Assistance Project, June 2011, P. 45.

Figure 7-2. Increasing Earnings in a Decoupled Utility (RAP)

[127] Response to DR 063.
[128] Response to DR 063.

The Company has provided examples of ways that it is lowering operational expenses to benefit customers:[129]

Careful evaluation of each component of overall compensation.

We note that utilities typically re-evaluate each element of overall compensation yearly or every few years. This cost-control tool is likely the same focus that would be implemented with or without decoupling. Whether or not deriving specifically or in part from decoupling in the current context, this is an approach to reducing operational expenses.

A current hiring restriction which requires approval of the hiring manager, as well as the President of Avista, the CFO, the CEO and the Sr. VP for Human Resources for all replacement or new hire positions.

This step is not a standard cost-control tool and may or may not be related to the influence of decoupling. It is unusual for a utility to implement this level of review for all replacement or new hire positions, although utilities may find it prudent to implement controls from time to time or (alternatively) to open up for new hiring in certain areas or for certain scarce special skills from time to time. Whether or not deriving specifically or in part from decoupling in the current context, this is an approach to lower operational expenses.

However, from an independent outside perspective, a potential problem we notice is that staffing cuts might be a little too deep. We see senior people with great command, knowledge and years of experience in their assigned areas; we see some staff assigned to understudy senior staff to provide for a system of succession and backup.[130] We do not see the new hires in general training or expected staffing depth for intermediate analysts or assistant analysts that would be typical staffing for a utility in the past. This helps in short term cost control, but we would like to see more staffing depth to insure hard won experience and tacit knowledge is not lost should one or two senior staff decide to retire.[131] We have a sense that staffing is a bit thin compared with other utility clients with whom we recently have been engaged for projects. What works as a short-run cost savings may not work as well long-term and may have long-term unintended consequences.

[129] Response to DR 063.

[130] In the response to DR 055, Avista notes that DSM staffing has been essentially stable from 2012 through 2017, though organization has been rationalized: “The number of energy efficiency staff has remained relatively stable over the years, but the structure has changed over time. Some years the staff levels have increased or decreased, including part timers, to meet the needs of programs and support staff. Starting in 2010 the structure included program managers, engineers, and account executives (for commercial customers) that reported to a Director along with a small group of EM&V and analytics staff that reported to a different Director. In June 2014 there was a reorganization and the program managers, engineers, and EM&V/analytics staff all started reporting to the same new Director. The account executives, of which only a portion of their time is for energy efficiency for commercial customers, continue to report to a different Director who oversees a range of customer services. From time to time the program managers have shifted programs around to better meet the needs of the programs and the inclusion of new programs as well in response to the discontinuation of some programs.” Our concern is limited to Rate & Regulatory staffing and DSM staffing – we did not look at other areas of the Company.

[131] In some ways, utilities are like university research labs – it may take one to five years of application to sufficiently learn a functional area.

Effective January 1, 2014, Avista no longer contributes toward medical insurance premiums for the retiree medical plan.

Beginning January 1, 2020, a new calculation method will shift more expenses to retirees.

To reduce the number of medical office visits, the Company is providing web and phone based 24/7 telemedicine and there is an on-site clinic.

Beginning in 2017, the Company has offered a High Deductible Health Plan along with the current self-insured plan.

Medical costs are an area that requires constant vigilance for cost-control. Medical cost-control steps (no longer contributing to premiums for the retiree medical plan, shifting more expenses to retirees, introducing a telemedicine option and offering a High Deductible Health Plan option) are all ways to reduce Company medical costs.

Since escalation of medical costs has been a very visible and long-term social problem in the United States, it is likely that the medical area would have been similarly addressed with or without decoupling. Whether or not deriving specifically or in part from decoupling, these steps lower operational expenses.

Effective January 1, 2014 the defined benefit pension plan was closed to all non-union employees hired or re-hired after January 1, 2014. This transfers risk to employees. The Company also now offers a lump sum payout to non-union employees, further reducing risk to the Company.

Utilities typically subscribe to high quality market surveys that provide industry benchmarks for employee salaries and benefits and then adjust salaries and benefits where possible to approximate these national benchmarks. This is one of the reasons why utility pay and benefit packages are generally better than those offered in most sectors of the national economy or in local communities.

We note the general trend across business sectors towards the replacement of defined benefit pensions by 401K plans. Although comparatively slow to develop in the utility industry, this is now also a utility industry trend, and so would be indicated by a relevant market study. However, benchmarking and market matching, while a very useful indicator approach may not be a fully adequate criterion in this area: additional criteria might be relevant and provide an alternative perspective. In the short-run, most employees will be in the defined benefit retirement system so there should be no short-run downside. In the intermediate and long-term, transferring retirement risk for employee families from the Company to the individual employees may have unintended effects.

From the end of WWII through the early 1970s, the United States experienced relatively high economic stability and shared economic growth. Since then, from a working person's perspective, not so much. This is in part because productivity gains have not transferred to workers while costs have increased so that the economy is much more fragile than surface appearance would suggest.

Since most of our analysis is based on looking backwards in time to evaluate how things have worked up to the present, we need to also make the jump to facing forward. If we envision the general economic situation in the United States as it belatedly and finally tries to come to grip with climate change and finds the situation so far advanced that adaptation has become extremely difficult, we get a very different picture than if we look back to the era that ended in about 1972. There is no guarantee of economic stability and there appears to be an increasing risk of political instability, so economics might be working within a different and reduced context. We have the sense that it is not unlikely that there will be growing percentages of customers in need of assistance, and that utilities may be needed as anchors for good jobs if there is a general economic recession ahead.

Other possible concerns are the thin profit margin for producers of fracked natural gas and the steep decline curve for fractured gas vs. conventional gas wells[132]; as well as the push towards exporting natural gas which would likely raise prices in the United States as a firm export market is established. However, we understand that Company projections of both price and supply indicate reliable supply at reasonable prices into the future.

One of the characteristics that makes utilities strong and able as organizations has been career commitment, which likely changes when defined benefit pensions end. Individual employees, like other nano-investors are largely at the mercy of the market. Non-professional, non-insider investors are typically hurt during cyclical market downturns and in the unusual or extreme events that exceed the "design basis" for normal projected market returns (extreme events like 9/11 or the so called "Great Recession" from which wages have not recovered). Climate change affects global availability of food, changes living conditions on most of the planet, increasingly acidifies the oceans and causes great migrations and problems of immigration.

In these changes, small investors, such as employees, likely do better in the long-run with an institutional guarantee between them and the downside effects of markets which, over a lifetime, tend to show patterns of stable growth punctuated by severe market events. In addition, with market fluctuations due to climate change and shortages, markets are not likely to be reliable for

[132] Fracked natural gas currently makes up roughly 70% of natural gas in the US and producers are having trouble making a profit due to both over-investment based on speculative financing and the sharp depletion curve for fracked natural gas compared with conventional natural gas. Fracked natural gas is a low-cost solution, but is economically fragile even without taking in to account local physical environmental damage to air quality, water supplies and land, as well as health effects and global climate deterioration due to fugitive methane release associated with fracking. We note in this connection that the current administration is facilitating methane release to the atmosphere and so is accelerating climate problems. On the positive side, the discovery of rock fracturing technology and the rapid expansion and further development of fracturing technology has become equivalent to a very large subsidy that benefits low-income and all other natural gas customers. However, as has been typical of the natural gas supply curve in the past, eventually the supply curve will turn down. At the same time, climate is warming will create a declining need for heating. For this critique, please see McLean, Bethany, "The Next Financial Crisis Lurks Underground," *New York Times*, September 1, 2018 (https://www.nytimes.com/2018/09/01/opinion/the-next-financial-crisis-lurks-underground.html). Also see: McLean, Bethany, *Saudi America: The Truth about Fracking and how It's Changing the World*. New York, New York: Columbia Global Reports, 2018.

the average investor. During this time, it might be valuable for utilities to restore defined benefit pensions to enable them to be an anchor in their communities and regions.

The Company is introducing more automation for IS/IT and is working towards providing longer contracts to venders in return for discounts.

From experience, the Information Services/Information Technologies areas have long been somewhat independent of utility organizational cultures. Utilities are very reliant on data and computer systems, yet these systems tend to be operated somewhat by their own internal logics which can sometimes present unexpected yet necessary new costs. Working towards discounts from venders in these areas is a useful approach to cost-control. Whether or not deriving specifically or in part from decoupling, this step lowers operational expenses.

We also make the following observations:

- In our interactions with management and staff, we found no indications of any lack of attention to cost control and operational efficiency. We believe that the company maintains a careful and prudent approach to controlling costs and we found no indication of any form of dysfunction or fractionalization within the organization.
- We found dedication to high performance, individual and group achievement of strong technical proficiency and a sense of personal and business commitment to public service.
- We found no indication of any cynicism, apathy or disaffection during the formal workday or in informal discussions with management and staff. Staff holds each other, corporately, to high standards.
- As noted previously, in the discussion of service quality, the service quality indicators (SQI) are good, which is an indirect indication of operational efficiency.

One additional aspect of operational efficiency is the relation of rate of return compared with utility cost of capital. This is not specifically a decoupling question, but it arises in decoupling. The concern is that if rate of return is consistently higher than utility cost of capital there could be an advantage in "gold plating" activities subject to the rate of return. As shown in Table 7-12 this relationship does not hold for Avista and so, no adverse effect of this type exists in Avista's decoupling.[133]

[133] DR 066 Attachment A. The Averch–Johnson effect is the academic name for what, in industry jargon, is usually referred to as "gold plating" or "high-grading". This is a theoretical "moral hazard" of regulated companies to engage in excessive amounts of capital accumulation in order to expand the volume of their profits. If companies' profits to capital ratio is regulated at a certain percentage then, depending on the gap there may be a strong incentive for companies to over-invest in order to increase profits overall. Investment is then optimized not for operational efficiency, but for administratively supported profit maximization. We do not see this happening with Avista decoupling. See: Averch, Harvey; Johnson, Leland L. (1962). "Behavior of the Firm Under Regulatory Constraint". *American Economic Review*. 52 (5): 1052–1069.

Table 7-12. Rate of Return vs. Cost of Capital – DR 066, Revised, Attachment A

-------------------- Washington Electric --------------------						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Normalized Rate of Return	7.16%	7.57%	7.92%	7.33%	7.33%	7.34%
Authorized Rate of Return	7.91%	7.64%	7.64%	7.32%	7.29%	7.29%
Normalized Return on Equity	8.70%	9.90%	10.60%	9.40%	9.40%	9.40%
Authorized Return on Equity	10.20%	9.80%	9.80%	blackbox	9.50%	9.50%
-------------------- Washington Natural Gas --------------------						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Normalized Rate of Return	5.44%	6.23%	5.79%	6.14%	7.96%	7.84%
Authorized Rate of Return	7.91%	7.64%	7.64%	7.32%	7.29%	7.29%
Normalized Return on Equity	5.20%	7.20%	6.40%	7.00%	10.70%	10.40%
Authorized Return on Equity	10.20%	9.80%	9.80%	blackbox	9.50%	9.50%
Notes: The Authorized Rate of Return for 2015 has been corrected as per discussion in the presentation/review meeting. The number in the original table was 7.64; the corrected entry is 7.32. The term "blackbox" means the information is not available because it is sealed by a settlement agreement.						

We see no current adverse impact on cost control and operational efficiency.

Summary – Task 7 (Adverse Impacts)

We find no conclusive evidence of current adverse impact of decoupling on cost control, operational efficiency, price signals or service quality. We have expressed two concerns for the intermediate to long-term for two cost-control approaches: making hiring reviews more extensive and so possibly creating some short-staffing problems over time; and moving away from defined benefit pensions. We address these two concerns in the Recommendations section.

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Section 8. Low-Income Appendix

The Avista Decoupling Evaluation RFP No. R-41321 provided two related Attachments to the Scope of Work: Attachment G - An Estimate of the Number of Households in Poverty Served by Avista Utilities in Washington State[134] and Attachment H - The Self-Sufficiency Standard for Washington State 2014.[135] Attachment G provides an estimate of how many Avista customers are below the Federal Poverty Level in counties served by Avista. Attachment H estimates the level of income required by households to achieve self-sufficiency without public assistance. We reviewed these two documents and correlated findings with the low-income energy assistance information that we reviewed for Task 3. This Appendix summarizes findings.

Attachment G - Estimate of the Number of Households in Poverty

This study provides estimates of the number of Avista low-income customers in the State of Washington. The estimates are based primarily on Census Tract data, particularly the American Community Survey which provides counts of household at different poverty levels for each census track. Within each tract, the study provides an estimated count of households with income at or below five multiples of the Federal Poverty Level (FPL): 50%, 125%, 150%, 185% and 200%.

Table 8-1 combines information from Attachment G with information provided in DR's related to Task 3 and compares the number of Avista low-income customers served by one or more energy assistance programs to the number of households estimated to be at or below 150% of the FPL.[136]

The sources and descriptions of data for each of the columns in Table 8-1 are presented below.[137]

- Columns (1,2) *An Estimate of the Number of Households in Poverty Served by Avista Utilities in Washington State*. These are Census 5-year rolling estimates for the period 2009-2013.
- Column (3) *An Estimate of the Number of Households in Poverty Served by Avista Utilities in Washington State*, is based on an estimate of the number of households at or below 150% of the FPL as reported in Attachment G.
- Column (4) DR 47 A, is the average number of bill assistance grants from all funding sources provided to Avista customers annually during the period 2012-2017.[138]
- Column (5) DR 49 A, is the average number of Avista Weatherization rebates annually during the period 2012-2017.

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[134] *An Estimate of the Number of Households in Poverty Served by Avista Utilities in Washington State*, Brian Kennedy, MS and D. Patrick Jones, Ph.D., Institute for Public Policy and Economic Analysis, May 2015.

[135] *The Self-Sufficiency Standard for Washington State 2014*, Diana M. Pearce, PhD, Center for Women's Welfare and the School of Social Work at the University of Washington, Revised August 2015.

[136] One hundred and fifty percent (150%) of the Federal Poverty Level (FPL) is the national LIHEAP eligibility standard used in most states to determine eligibility for energy assistance.

[137] Responses to DR's: 047 Attach. A, 036 Attach. A

[138] The data from Attachment G covered the period 2009-2013. Based on the data available in evaluation DRs for columns (4) and (5) we used the average number of customers served over the 2012-2017 period. While the data does not match chronologically, using averages helps to eliminate yearly variations.

- Column (6) = [Column (4) + Column (5)]/Column (3), an estimate of the percentage of LIHEAP Eligible Households served by energy assistance and Avista Weatherization.[139]

Table 8-1. 150% of Poverty or Less - Receiving Bill Assistance or Avista Weatherization

	(1)	(2)	(3)	(4)	(5)	(6)
County	**Estimated Households**	**Avista Residential Customers**	**Estimated Households Eligible for LIHEAP**	**Avista Customers Receiving Bill Assistance**	**Avista Customers Receiving Weatherization Assistance**	**% of LIHEAP Eligible Customers Receiving Energy Assistance**
Adams	5,747	4,540	1,692	399	8	24%
Asotin	9,052	9,294	2,264	848	32	39%
Ferry	1,669	1,630	667	189	1	28%
Franklin	2,683	167	61	-		0%
Grant	1,163	10	3	-		0%
Klamath	NA	NA	NA	1		NA
Klickitat	3,656	763	263	21	1	9%
Lincoln	4,463	3,462	866	252	3	29%
Shoshone	NA	NA	NA	1		NA
Skamania	764	320	82	6	1	8%
Spokane	186,259	169,287	43,613	13,044	182	30%
Stevens	17,569	19,972	6,113	1,754	17	29%
Whitman	16,630	17,437	7,322	1,040	15	14%
Total	**249,657**	**226,882**	**62,946**	**17,553**	**260**	**28%**

This analysis finds that on average approximately 28% of the estimated LIHEAP eligible households (150% of Poverty or less) receive some type of energy assistance from one or more of the following programs: LIRAP, LIHEAP, Project Share, MISC or Avista Low-income Weatherization. The percentage of estimated LIHEAP eligible customers receiving assistance in each county ranged from 8% to 38%.

Attachment H - The Self-Sufficiency Standard for Washington State 2014

This report[140] presents and analyzes the Self-Sufficiency Standard for Washington State in 2014. This measure describes how much income families of various sizes and composition need to make ends meet without public or private assistance in each county of Washington State. The Self-Sufficiency Standard is a measure of income adequacy based on the costs of basic needs for working families: housing, child care, food, health care, transportation, and miscellaneous items, as well as the cost of taxes and the impact of tax credits. The Standard is intended to provide a more detailed, up-to-date, accurate, and comprehensive measure of economic well-being than the Federal Poverty Level.

[139] It should be noted that Avista customers receive weatherization assistance from other programs such as the US Department of Energy Weatherization Assistance Program, which were not documented in this evaluation, since these services are not tracked by Avista. See Avista Response to Data Request No. 029(1).
[140] Pearce, Diana M., op cit.

We reviewed Attachment H and extracted the Self-Sufficiency Standard for the same 11 counties analyzed for Attachment G above. Table 8-2 provides a summary of the percentage of the FPL that a family would need to earn to achieve Self-Sufficiency in each of the 11 counties. This percentage varies from a low of 171% to a high of 235% of FPL to achieve Self-Sufficiency, depending on location and household composition.

Table 8-2. Self-Sufficiency Standard Expressed as a Percentage of Poverty

	One Adult One Preschooler		One Adult One Preschooler One School-Age		Two Adults One Preschooler One School-Age	
	Self-Sufficiency Standard					
County	**Annual**	**Percentage of Federal Poverty Level (FPL)**	**Annual**	**Percentage of Federal Poverty Level (FPL)**	**Annual**	**Percentage of Federal Poverty Level (FPL)**
Adams	$30,449	194%	$37,601	190%	$45,295	190%
Asotin	$29,993	191%	$34,815	176%	$42,549	178%
Ferry	$30,919	197%	$43,738	221%	$50,680	212%
Franklin	$35,210	224%	$46,078	233%	$52,936	222%
Grant	$32,229	205%	$38,810	196%	$46,653	196%
Klickitat	$31,915	203%	$44,088	223%	$50,998	214%
Lincoln	$28,991	184%	$33,805	171%	$41,563	174%
Skamania	$33,187	211%	$40,340	204%	$47,776	200%
Spokane	$36,023	229%	$46,453	235%	$53,136	223%
Stevens	$34,009	216%	$44,912	227%	$51,805	217%
Whitman	$38,420	244%	$48,209	244%	$55,552	233%

The variation of Washington’s Self-Sufficiency Standard by county for each of three family types is illustrated in Figure 8-1. While there is meaningful variation across both family types and counties, results cluster somewhat above 200% of FPL. We can, conservatively, use 200% of the FPL to estimate need. In a more rigorous approach, we would need to take both family type and county directly into account, but since 200% is above the 150% of FPL or lower percentages used for some Avista low-income programs we can reasonably use 200% for practical purposes. Attachment G provides an estimate of the number of Avista customers at or below 200% of poverty as illustrated in Table 8-3.

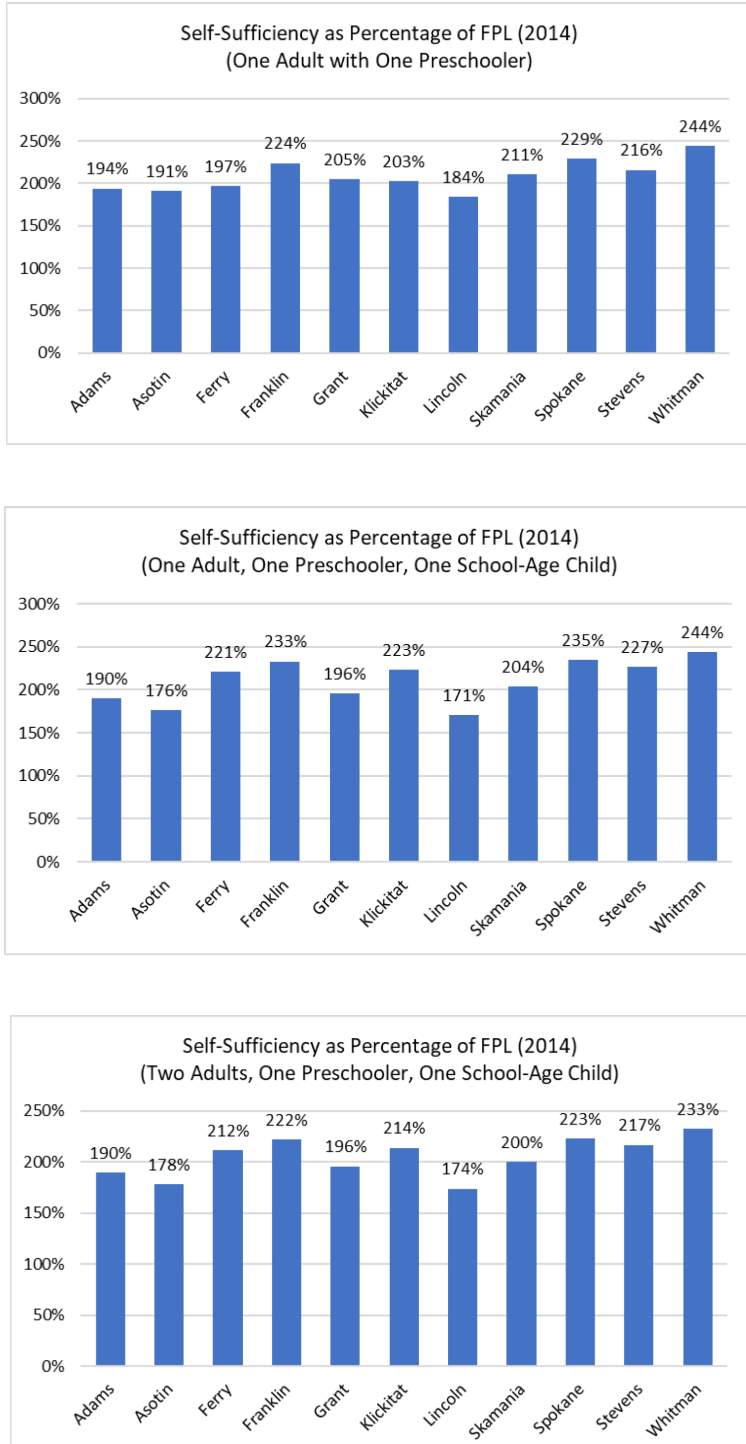

Figure 8-1. Variation of Self-Sufficiency Standard across Washington Counties

In Attachment G, using calculations based on the American Community Survey, Kennedy and Jones estimate that, on average, thirty-seven and one-half percent (37.5%), of Avista Customers are at or below 200% of FPL (Table 8-3).[141]

During the period 2012-2017, bill assistance or Avista Weatherization services were provided to 17,813 customers per year.[142] Based on the Self-Sufficiency Standard model this service record comprises about twenty-one percent (21%) of the 85,159 Avista customers whose incomes are at or below the Self-Sufficiency Standard, when approximated at 200% of the FPL.

Table 8-3. Results at 200% Poverty based on American Community Survey

County	American Community Survey Estimated Households	Total Avista Customers (Households)	Estimated Avista Customers: 200% FPL	Estimated Share of Avista Customers: 200% FPL
Adams	5,747	4,540	2,310	50.90%
Asotin	9,052	9,294	3,488	37.50%
Ferry	1,669	1,630	813	49.90%
Franklin	2,683	167	85	51.10%
Grant	1,163	10	5	49.80%
Klickitat	3,656	763	376	49.20%
Lincoln	4,463	3,462	1,242	35.90%
Skamania	764	320	100	31.30%
Spokane	186,259	169,287	59,532	35.20%
Stevens	17,569	19,972	8,412	42.10%
Whitman	16,630	17,437	8,796	50.40%
Total	249,657	226,882	85,159	37.50%

Making Sense of Federal Poverty Level vs. Income Insufficiency

Pearce compares several "benchmarks of income", including the Self-Sufficiency Wage, Welfare (TANF, SNAP & WIC), the Federal Poverty Level, the full-time minimum wage for Washington and the Department of Housing and Urban Development Income Limits for three levels of low-income (the top level is the highest income eligible for federal housing assistance: 80% of area median income; in addition, there is a Low-income Limit and a Very Low-income Limit). Each of these is a separate indicator that a household is in a situation of income difficulty.[143]

Of these benchmarks, the most used in the United States is a multiple of the federal poverty level (FPL), yet this is also one of the most challenged indicators. The fact that almost no agency uses the FPL, but, instead, agencies use a multiple of the FPL for program eligibility suggests that problems with the FPL are universally recognized. The FPL was created using 1950s data in the early 1960s. It assumes a stereotypical 1950s family with a single wage earner and a full-time unwaged person at home to do the work of raising children, housework, and meal preparation. In the 1950s, one wage earner could typically support a family, unlike today when it usually takes two fulltime workers to earn slightly more than one worker earned in the 1950s, accounting

[141] *An Estimate of the Number of Households in Poverty Served by Avista Utilities in Washington State*, Brian Kennedy, MS and D. Patrick Jones, Ph.D., Institute for Public Policy and Economic Analysis, May 2015, page 7.
[142] This is the sum of totals for columns 4 and 5 in Table 8-1.
[143] Pearce, Diana M, op cit., Pp. 28-29.

for inflation.[144] In low-income families, typically older children also do part-time work to bring in money for the household and (for some) volunteer for the armed services when they become of age in order to be able to send money back to their parents and keep their family viable. Also, as pointed out by Pearce, the official FPL was based on a single indicator (the cost of the lowest level of food that could sustain a family), which was then multiplied by the number three. Each year, this highly flawed indicator[145] is adjusted for inflation using one of the Bureau of Labor Statistics (BLS) consumer price indexes (CPIs). This type of adjustment is itself flawed because the BLS CPI seriously underestimates inflation over a period of years. The outcome is a severely underestimated benchmark sequentially adjusted each year by a flawed multiplier, so it is often argued that the FPL is severely flawed. Indeed, the Census Bureau itself states, "the official poverty measure should be interpreted as a statistical yardstick rather than as a complete description of what people and families need to live."[146]

In contrast, the US Department of Housing and Urban Development benchmark of 80% of area median income automatically adjusts each year as incomes change,[147] though it is sensitive only to the median of the income distribution and not sensitive to the increasingly severe income inequality that we experience.

The most well-grounded method is the Self-Sufficiency Standard benchmark used by Pearce and developed jointly by Wider Opportunities for Women and the Ford Foundation. This method is the current version of the household budget approach in use by social workers for the past one-hundred years. It is updated every few years by changes to the costs of items required by households for a lower-moderate level of living and is based on family size and the ages of persons in the household. Table 8-4 illustrates the specific items that comprise the Washington Self-Sufficiency Standard for Spokane County in 2014.[148] Pearce has calculated a specific Self-Sufficiency Standard for each county in Washington State. These studies are repeated approximately every three years.

If we were to use the Poverty Guidelines (only) for Spokane County in 2001, one-hundred and fifty percent (150%) of poverty for a single adult is $12,885. In 2017, it is $18,090. This is an increase of about 140% between 2001 and 2017 (Table 8-5). If we were to use the Self-Sufficiency Standard (only), for Spokane County in 2001, the standard for a single adult is $14,910. For 2017, it is $18,972. This is an increase of about 127%, yet there is another factor

[144] Though disposable income is less for today's two-income families than it was for counterpart single-income families in the 1950s.
[145] Highly flawed since based on a single indicator and because the diet selected is no longer available and since the food items required several hours of work to make the food edible. It was a good effort for the time; there was no official poverty indicator before this.
[146] Carmen DeNavas-Walt, Bernadette Proctor, and Jessica C. Smith, "Income, Poverty, and Health Insurance Coverage in the U.S.: 2012," U.S. Census Bureau, Current Population Reports, Series P60-245, Washington, D.C. (U.S. Government Printing Office), http://www.census.gov/prod/2013pubs/p60-245.pdf (accessed June 24, 2014).
[147] Due to a long-term shortage of public housing, although the upper eligibility limit is 80% of area median income, most apartments that become available are assigned to households with lower incomes.
[148] Pearce, Diana M, op cit., P. 103.

to take in to account: the amounts for both 2001 and 2017 are higher for the Self-Sufficiency Standard than for the Poverty Guidelines.

While there is not much difference for a single adult, the real strength of the Self-Sufficiency Standard is shown in the remaining columns of these tables. The Self-Sufficiency Standard takes in to account, not only family size, but also ages of household members and it is based on actual cost of essential items for a specific year. The size of the gap between these two methods is about ten percent (10%) for the single adult in 2017, fifty-six percent (56%) for a household with one adult and one preschooler, and about fifty-two percent (52%) for a household with two adults, one preschooler and one school-age child. As has been noted by Pearce, the relative failure of CPI measured inflation is demonstrated in the method's inability to capture the actual differences measured in the Self Sufficiency Standard approach.[149]

The Washington Self Sufficiency Standard is based on the family budget method and is updated every three years to capture data on changes to the costs of items required by households, characterized by family structure and the age of household members. The Standard is based on achieving a lower-moderate level of living and is calculated at the county level. In contrast, federal poverty guidelines, though based on the number of members of a household, are not based on family structure and not age adjusted or based on county-level costs. The CPI tends to lack adequate information while the Self Sufficiency Standard does not.

Table 8-4. Monthly Costs included in the Self-Sufficiency Standard - Spokane 2014

MONTHLY COSTS	**Adult**	**Adult + Preschooler**	**Adult + Infant Preschooler**	**Adult + Preschooler School-age**	**Adult + School-age Teenager**	**2 Adults + Infant**	**2 Adults + Preschooler School-age**	**2 Adults + Infant Preschooler School-age**
Housing	$571	$773	$773	$773	$773	$773	$773	$1,105
Child Care	$0	$692	$1,492	$1,224	$532	$800	$1,224	$2,024
Food	$245	$371	$487	$560	$647	$593	$768	$850
Transportation	$257	$266	$266	$266	$266	$507	$507	$507
Health Care	$113	$392	$405	$410	$439	$451	$467	$479
Miscellaneous	$119	$249	$342	$323	$266	$312	$374	$497
Taxes	$189	$435	$654	$591	$365	$513	$615	$935
Earned Income Tax Credit (-)	$0	($33)	$0	$0	($157)	$0	$0	$0
Child Care Tax Credit (-)	$0	($60)	($100)	($100)	($63)	($50)	($100)	($100)
Child Tax Credit (-)	$0	($83)	($167)	($167)	($167)	($83)	($167)	($250)
SELF-SUFFICIENCY WAGE								
HOURLY	$8.49	$17.06	$23.59	$22.05	$16.49	$10.84 per adult	$12.67 per adult	$17.18 per adult
MONTHLY	$1,494	$3,002	$4,152	$3,881	$2,903	$3,816	$4,461	$6,047
ANNUAL	$17,923	$36,023	$49,825	$46,573	$34,830	$45,796	$53,532	$72,564
EMERGENCY SAVINGS (Monthly Contribution)	$36	$81	$109	$105	$95	$50	$61	$79

[149] Pearce, Diana M., Attachment H – *The Self-Sufficiency Standard for Washington State, 2014*, op cit., P. 27

Table 8-5. 150% Poverty Guidelines (2001 vs. 2017)

Independent of County (2001 vs. 2017) 150% Poverty Guidelines (Only)			
Year	**Single Adult**	**One Adult with One Preschooler**	**Two Adults with One Preschooler and One School-Age Child**
2001	$12,885	$17,415	$26,475
2017	$18,090	$24,360	$36,900
Percent Change	140%	140%	139%

Table 8-6. Self-Sufficiency Standard Spokane County (2001 vs. 2017)

Spokane County (2001 vs. 2017) Self-Sufficiency Standard (Only)			
Year	**Single Adult**	**One Adult with Preschooler**	**Two Adults with One Preschooler and One School-Age Child**
2001	$14,930	$25,094	$39,428
2017	$18,972	$38,103	$56,010
Percent Change	127%	152%	142%

Table 8-7. 150% of FPL vs. Self-Sufficiency Standard, Spokane County, 2001

Spokane County (2001) 150% Poverty Guidelines vs. Self-Sufficiency Standard			
Calculation Method	**Single Adult**	**One Adult with Preschooler**	**Two Adults with One Preschooler and One School-Age Child**
150% FPL	$12,885	$17,415	$26,475
Self-Sufficiency Standard	$14,930	$25,094	$39,428
Percent Difference	116%	144%	149%

Table 8-8. 150% of FPL vs. Self-Sufficiency Standard, Spokane County, 2017

Spokane County (2017) 150% Poverty Guidelines vs. Self-Sufficiency Standard			
Calculation Method	**Single Adult**	**One Adult with Preschooler**	**Two Adults with One Preschooler and One School-Age Child**
150% FPL	$18,090	$24,360	$36,900
Self-Sufficiency Standard	$18,972	$38,103	$56,010
Percent Difference	105%	156%	152%

A useful analysis of what happened to the CPI is provided by ShadowStats (Figure 8-2). In this figure, the top line (blue) is the ShadowStats CPI and the bottom line (red) is the BLS CPI. Note that the two measures are nearly identical until about 1983 at which point they begin to diverge. The two curves continue with very similar shapes, except for the growing spread of vertical distance between comparable points on each curve. The ShadowStats CPI continues the original method of the BLS CPI (and the method for a price index as described in older economic textbooks). Changes in the original BLS CPI method were introduced gradually under both Republican and Democrat administrations. These changes have academic explanations yet tend to move the indexed inflation down, having the effect of making things look better than they are.[150] They function to lower social security increases, wage increases indexed to the BLS CPI and other government program expenditures tied to the CPI. The latest BLS innovation is movement towards a "chained CPI" which used geometric rather than arithmetic means. This will also make the CPI register weaker inflation than that known to the population through lived experience.

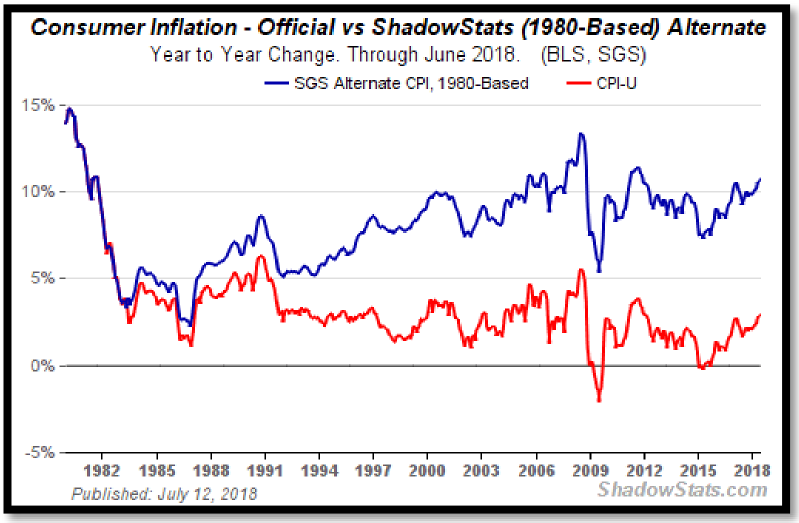

Figure 8-2. Historical Divergence of BLS CPI (Courtesy of ShadowStats.com)

Level of Rigor

These differences in methods have several implications in the estimation of the number of low-income customers. Table 8-1 suggests that about twenty-eight percent (28%) of Avista's residential service population is low-income, based on the one-hundred and fifty percent (150%) of poverty level criterion, as in most states. Table 8-3 shows that if a two-hundred percent (200%) of poverty criterion is chosen, the result is about thirty-seven percent (37.5%) of residential customers. The Self Sufficiency Standard approach tends to center on two-hundred percent (200%) though it varies with family type and by county. In Table 8-2, values range from 174% to 233% depending on county and family type.

The result in the number (and percentage) of low-income households in Avista's service territory depends on the method of analysis selected. Selection of method depends on a choice of level of rigor. Most utilities simply go with a percentage like one-hundred and fifty percent (150%) of poverty because it is simple. It is administratively convenient since the appropriate poverty

[150] (http://www.shadowstats.com/alternate_data/inflation-charts) ShadowStats charts must be published without modification in any way and must contain, under the chart, "Courtesy of ShadowStats.com" See also: Boring, Perrianne, "If You Want to Know the Real Rate of Inflation, Don't Bother with the CPI", Forbes, February 3, 2014 (https://www.forbes.com/sites/perianneboring/2014/02/03/if-you-want-to-know-the-real-rate-of-inflation-dont-bother-with-the-cpi/#47059396200b). For an opposing perspective, see Greenlees, John S. and Robert B. McClelland, "Addressing Misconceptions about the Consumer Price Index." *Monthly Labor Review*, August 2008, Pp. 3-19 (https://www.bls.gov/opub/mlr/2008/08/art1full.pdf).

numbers and program guidelines are published each year in the Federal Register and a multiple of Poverty can be easily implemented.

A middle level of rigor would look more closely at the variations from a textbook approach in calculating the BLS CPI and choose, instead, the ShadowStats CPI (which is proprietary but easy to access by crossing a paywall). Or, by melding the BLS CPI and the ShadowStats CPI using a simple ratio following a study of both methods. This approach would offer the same administrative convenience as a low rigor approach but would be more accurate.

A high level of rigor would use neither the official definition of Poverty based on the original flawed analysis and flawed updates produced by the government using the BLS CPI (as modified away from original BLS practice and textbook method many times). A high level of rigor would begin with the existing work on the Self Sufficiency Standard, calculated and updated for Washington approximately every three years by the Center for Women's Health at the University of Washington School of Social Work. This is the most truthful and realistic method. However, it would require calculation by county and it would be tailored to family structure by ages of household members and not only to family size. Strictly, it would have to be administratively applied at a county level, and provision of different levels of eligibility by county could be an administrative concern. The problem is not just optics, but, for example, households located near county borders or other possible needs for exceptions. However, if this high-rigor method were used for analysis, an administrative simplification could be employed for program administration.

The implication of this analysis is that more households need help than are indicated by the Poverty Guidelines as adjusted by the BLS CPI. We recommend using the using the Self Sufficiency Standard. However, we are aware that rigor in analysis might need to be accompanied by simplification to meet the needs of program administration.

At the same time, in evolving the structure and scope of payment assistance and weatherization assistance, the cost to customers providing the assistance must be considered and balanced. Customers just above the cutoff for eligibility are in essentially the same financial bind as customers eligible for assistance, so attention could be focused on "feathering out" assistance at the top of the eligibility range, or to exempting from tariffs that support assistance to low-income customers those customers who are in income groups just above the eligibility range.

Understanding Low-Income within the Overall Allocation of Income

If we consider the allocation of income for Washington, the income donut shown in Figure 8-3 provides an image that is easy to remember. This is the income donut for 1990, computed from census data.[151] For comparison, the income donut for 2000 was computed[152] and is shown in Figure 8-4.

If we compare the two donuts, we see that income for the upper twenty percent (20%) of households by income moved up by eight percent (8%) from 1990 to 2000. The bottom twenty percent of households dropped from five percent (5%) to four percent (4%). The lower middle dropped one percent (1%), the middle five percent (5%) and the upper middle dropped two percent (2%).

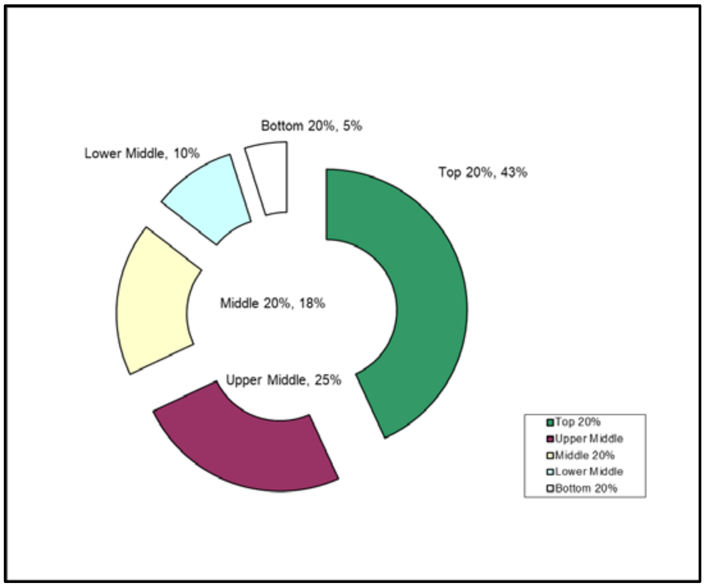

Figure 8-3. Income Donut for Washington State (Census 1990)

From the end of WWII through the early 1970s, the United States increasingly took on many characteristics of an economic democracy as income shares increased throughout most of society and shares to upper income groups dropped; for example, the upper one percent (1%) lost income share during this era. From about 1970 or 1972, the process reversed, and income flow has concentrated more and more toward the very top of the distribution of income to households. Within the upper five percent (5%) this flow to the top repeats very strongly; within the upper 1% the pattern again repeats but more intensely.

The two income donuts shown only indicate a little of this change. However, income inequality is increasing dramatically. As suggested by the two figures presented, income share is taken from the bottom through the upper middle and transferred into the top quintile. However, within

[151] Source: Columns 1 and 2 from Table P080, Household Income in 1989, Census 1990 Summary Tape File 3 - Sample Data.
[152] Source: Columns 1 and 2 from Table P52, Household Income in 1999, Census 2000 Summary File 3 - Sample Data.

the top quintile the same pattern of extraction and allocation occurs with income moving from the lower parts of the top quintile to the upper one percent (1%).

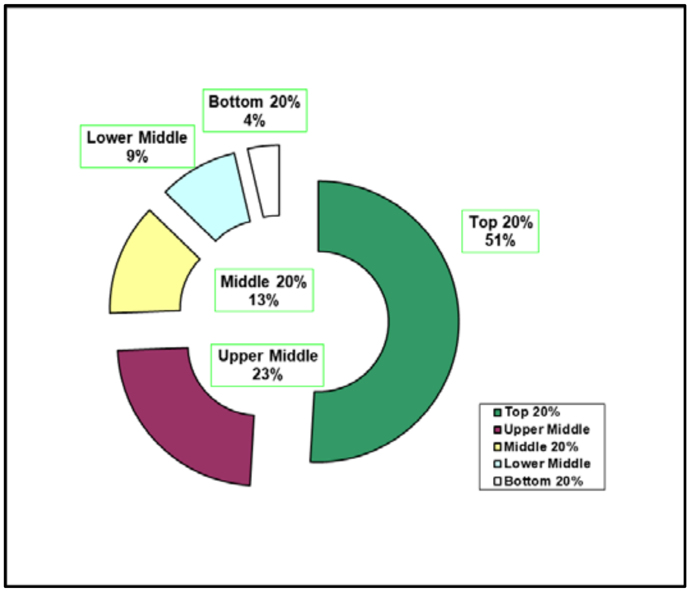

Figure 8-4. Income Donut for Washington State (Census 2000)

This pattern of income allocation creates a dilemma for providing support for low-income households, since income share is being taken from those households that would normally have been able to support some form of low-income assistance in the past. This is a dilemma for funding low-income weatherization and payment assistance and should be taken in to account in informing development of a low-income rate. Balance is very important.

Section 9. Weather Appendix

Everyone knows the weather is changing. The NW Climate Hub[153] has issued a drought forecast (Figure 9-1) as of July 31, 2018, beginning in August 2018. The forecast includes a map of potential wildland fire areas (Figure 9-2). While these projections become a quickly dated and one-time forecast, they report on an underlying change in the weather. The projections are consistent with rapid (in geologic time) climate warming. Nearly every year now, there is more warm weather, including warm evenings. The trees from California up through British Columbia (and over to Colorado and Utah) are stressed and thousands are dying. The "new normal" is a warming trend with statistical fluctuation. The "new normal" also is a process (flow) variable – it is not static, but moving. It is getting warmer and warmer and there is no apparent end to the warming on a typical human scale of time.

A combination of high temperatures, low humidity, and dry to record-dry conditions has increased fire danger.

• Wildfires continue to threaten lives, property, crops, rangeland, and forests.

• Drier-than-normal conditions are expected to continue across most of the region, which will perpetuate fire danger. CURRENT CONDITIONS

• OR and WA have been experiencing dry weather. Combined with high temperatures, this led to the designation of moderate drought in the Olympic Peninsula, abnormal dryness in parts of eastern WA, and the introduction of severe drought across the Cascades and into the Willamette Valley last week. Southern ID and the panhandle are abnormally dry with some areas of moderate drought.

• According to the Northwest River Forecast Center, monthly precipitation through July 30, 2018, is below 50% of normal. Over the last 90 days, precipitation totals for parts of western OR and WA were the lowest they've been in at least 40 years.

Figure 9-1. Drought Conditions

[153] https://www.drought.gov/drought/sites/drought.gov.drought/files/StatusUpdate_PNW_July31Final.pdf.

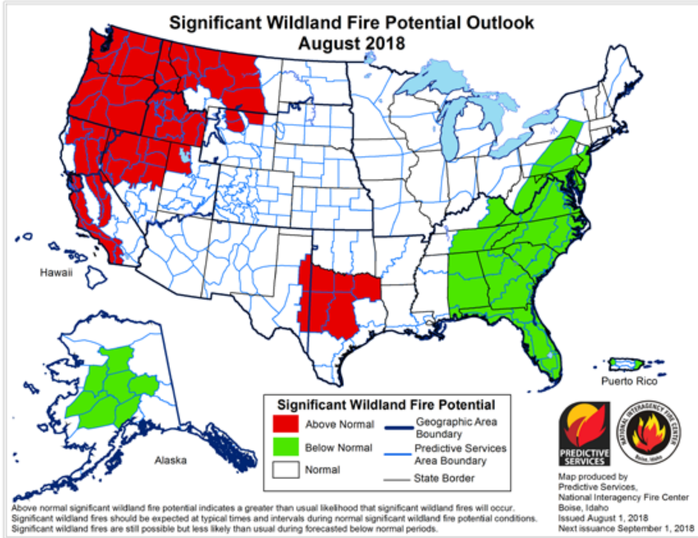

Figure 9-2. Wildland Fire Potential Outlook

Within this context of changing weather, the first thing to note in the two figures below (Figure 9-3 and Figure 9-4) is the increasing prevalence of warm years with fewer heating degree days and more cooling degree days. The orange bars denote years that are warmer than normal. Although there is statistical variation, the orange bars are mostly stronger than the blue bars and are increasingly frequent. Occasional years with more heating degree days occur, but years with more heating degree days are becoming scarcer. The bars each represent the difference in heating or cooling degree days to a base of 65˚ Fahrenheit, calculated using a rolling thirty-year average (normal) weather.[154]

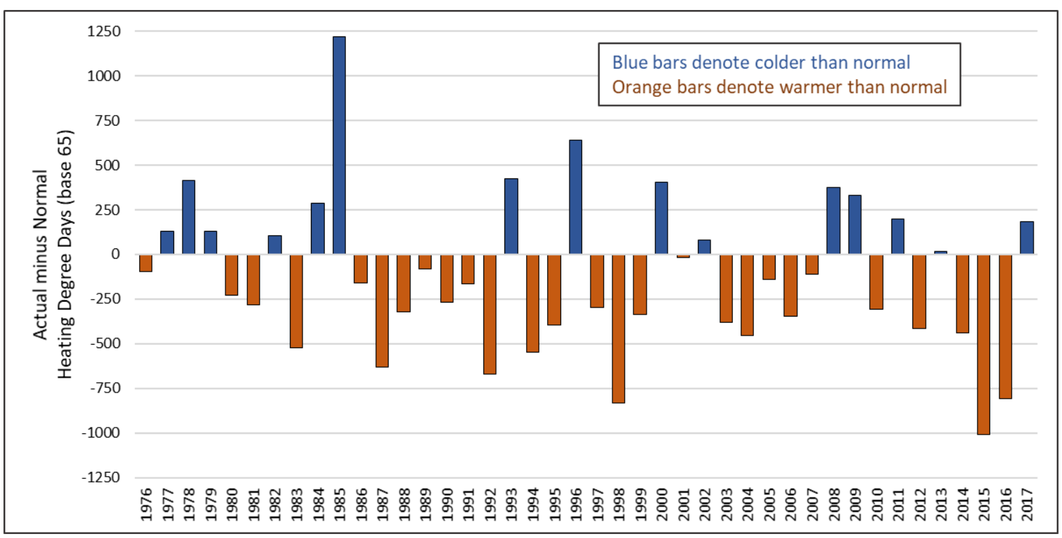

Figure 9-3. Pattern of Heating Degree Days (Spokane)

[154] Beginning in 1947 values are from the Spokane airport (GEG) weather station. Values in Figure 9-3 and Figure 9-4 run from 1976 through 2017 (a range of 42 calendar years).

Sequences of Warm and Cold Years

Looking at Figure 9-3 or Figure 9-4, the frequency of cold years is decreasing, but also warm years tend to run in series and their values are becoming stronger, while cool years run in short blocks of one or two years and their strength is becoming weaker (as indicated by the length of the bars).

For decoupling designs, this pattern is important. In the abstract, we might think of a deferral mechanism as easily balancing over two years if the pattern of years is alternately warm and cold. But since warm years are occurring in runs and the runs are appearing longer for warm years (as well as warm years becoming stronger), this factor should be considered in decoupling design in relation to defeating any “snowballing” effect, especially for natural gas rate groups. If the pattern holds, we can expect declining need for heating in Winter. Avista’s decoupling design is special in that it allows for ratchetting decoupling rates to amortize higher levels of deferral balances (it works on *incremental* changes); a good design feature. A practical implication of this ratchetting will be decoupling rates that may look high as a percent of total revenue (exceed the three percent (3%) cap, since the mechanism works incrementally each year), until the rates reset following a normal or colder than normal year or in the next rate case.[155]

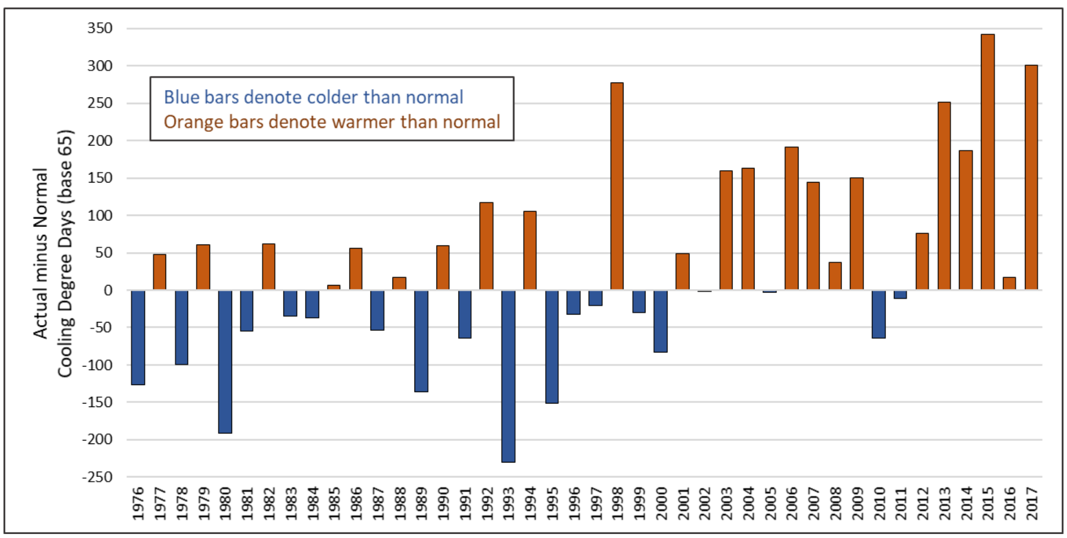

Figure 9-4. Pattern of Cooling Degree Days (Spokane)

[155] In this paragraph, we use “normal” in the “old normal” sense of a 30-year moving average rather than in the sense of the recent flow of the “new normal” which might be based on fifteen years or most recent seven years, for example. The “old normal” is a flow variable, as is the “new normal”. From a mathematical perspective, the rate of flow increases substantially in a smaller set of most recent years. The mathematics reflects physical change.

Zero Heating Degree Days

Using data from the Spokane airport weather station (GEG), we can project the approximate year when there will be zero heating degree days (HDD). The practical implication of an indicator that tends towards zero HDD is that the need to turn on heat for buildings tends towards zero. In a simple regression of HDD on year, beginning in 1947 (when Spokane's weather station was moved to the airport), it is easy to see that HDD is declining over time (Figure 9-5). Using the parameter estimates from Table 9-1, we get a constant of 20,890 and a slope of -7.120. Using the standard equation of:

$$y = mx + b,$$

Or, in this application:

HDD = (-7.120)(YEAR) + 20,890

0 = (-7.129)YEAR + 20,890

(7.129)(YEAR = 20,890

YEAR = (20,890)/(7,129)

YEAR = 2934

Solving for the case in which HDD = 0, we get the year 2934

2934 – 2018 = 916

Or, about 916 years from now.

Table 9-1. Model Summary and Parameter Estimates

Model Summary and Parameter Estimates

Dependent Variable: HDD65

	Model Summary					Parameter Estimates	
Equation	R Square	F	df1	df2	Sig.	Constant	b1
Linear	.101	7.750	1	69	.007	20890.153	-7.120

The independent variable is Year.

This is a very *conservative* estimate, since we use airport data rather than a carefully developed climate model. Also, since the strength of the climate warming has shown itself only since about the year 2000, data from 1947 (the year our data series begins) is likely not relevant. In fact, even the "old normal" method would employ 30 years of data, rather than 71 years.

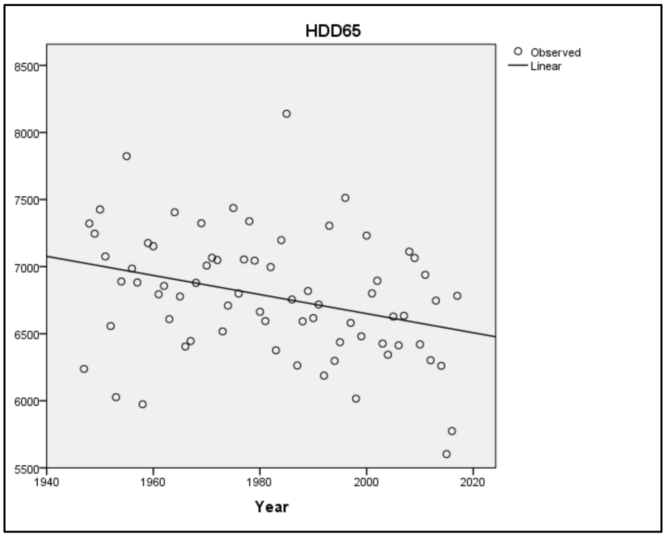

Figure 9-5. Regression of HDD on Year

If we reduce the years in the analysis to the 18 most current and re-run the analysis using the airport data beginning in 2000, the year in which HDD is zero is 2175 (or 157 years from now). If we re-run using only the 8 most recent years beginning in 2010, the year in which HDD is zero is 2104 (86 years from now). Figure 9-6 and Figure 9-7 show these relationships for different numbers of analysis years, reaching back from the most current data which is for calendar 2017.

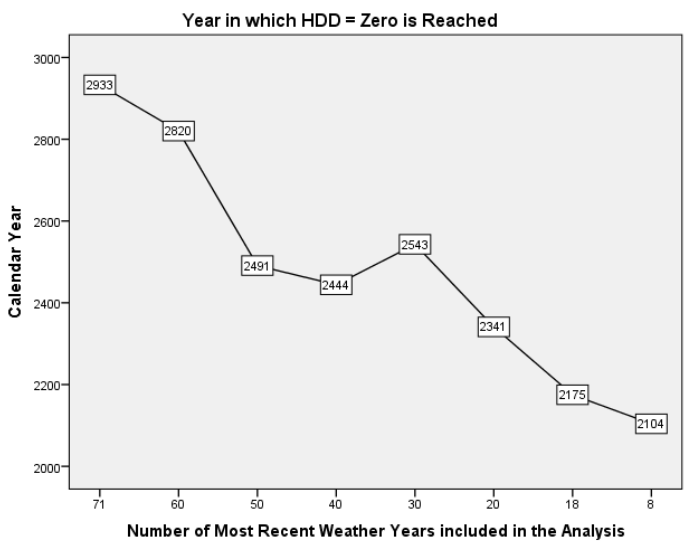

Figure 9-6. Year in which HDD = Zero is Reached, Using different Numbers of Analysis Years

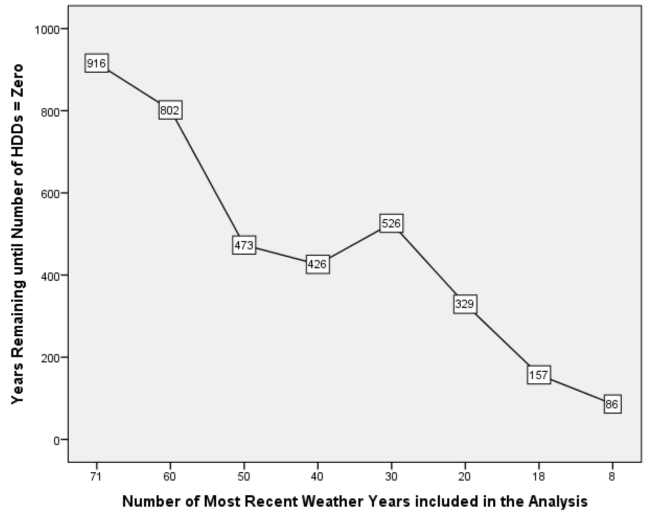

Figure 9-7. Years from 2018 until Zero HDD, using different Numbers of Analysis Years

We need to note that these are only the results of standard regression analysis and not science. Climate scientists tend to be very careful and conservative and do not like to project for more than about 100 years since the error bands around their results increase with time and there may be points of inflection and dialectical oppositions that are not yet well understood.[156] However, we are in a constantly moving new normal and these estimates are an attempt developing useful indicators rather than science.[157] The range of 916 to 86 years is a large range (note that we have not provided error bands). Yet a very big thing is happening, irreversible on a typical human scale. And, the reason for looking at most recent years is connected to physical phenomena with an increasing flow rates. So, how one interprets these numbers and these calculations depends on one's sense of physics.

While science must be quite conservative almost all of the time, persons with business sense and those with responsibility for public administration must be more practical so as to be aware in advance of things "hidden in plain sight." We suggest these calculations be considered as indicators, each with a different number of data points (calendar years of weather information from past years). Each of the indicators can be calculated each year so as to form a data series

[156] An example of dialectical tension is that physical constants such as the estimate of 100 years for carbon (as a generic for greenhouse gas) to reach a sink (or 20 years for fugitive methane) are unlikely to hold as sinks become overloaded. Vegetation as a source of carbon sequestering is expected to reverse at some point and become a carbon source (for example, from forest fires as trees and grass are increasingly stressed). Another tension is the expectation that primary ocean currents may change. Another is that air rivers have changed and are continuing to change, altering the behavior of hurricanes and rain storms. Another is the loss of snow cover which shifts wide areas from reflection to absorption. Dialectical analysis is required to take these kinds of factors into account.

[157] Why doesn't science give us more certain answers to our weather questions? Because it is young and underdeveloped. If we date modern science somewhat conservatively from the date of founding of the Royal Society of London for Improving Natural Knowledge in 1660, that is only 358 years ago, essentially a blink of the eye. To help with understanding time, the Long Now foundation advocates thinking in 10,000-year blocks and would write the founding year as 01660, while this report is submitted in 02018. If one thinks in a 10,000-year block, then science in 02018 is essentially new and primitive. However, a system of moving indicators may be relevant for organizational decision making.

constructed as a moving average in the same way that the traditional 30-year “normal” is calculated.

It is not good enough to revert to the 30-year normal. Clearly, the curves in Figure 9-6 and Figure 9-7 show fluctuation and this should be considered; but they also show an increasing tendency to bring the zero HDD year rapidly closer in time. For practical decisions, the decision-maker might maintain and review each indicator and act on those that appear most relevant to the purpose at hand. This analysis suggests that the 30-year normal is no longer a useful indicator. It is not a good indicator of the moving new normal.

We suggest, for now, running 30 years, 20 years, 15 years and 10 years and developing the curves for these indicators and then carrying the indicators into the future. We suggest that the 20-year indicator is the right one to rely on right now, that the 30-year indicator is not a good fit right now due to systematic changes in the weather (climate warming), and the 15-year and 10-year indicator will be more sensitive but also less stable than the 20-year indicator. The 30-year and the 20-year indicators will, of course, get better over time assuming the climate turn is the “new normal” and more and more warm years replace the cooler years at the beginning of each moving average. Figure 9-8 shows that the 20-year, 15-year, and 10-year averages are quicker to register the decline in HDD than the 30-year measure, though as the downward trend in HDD continues, the curves are converging.[158]

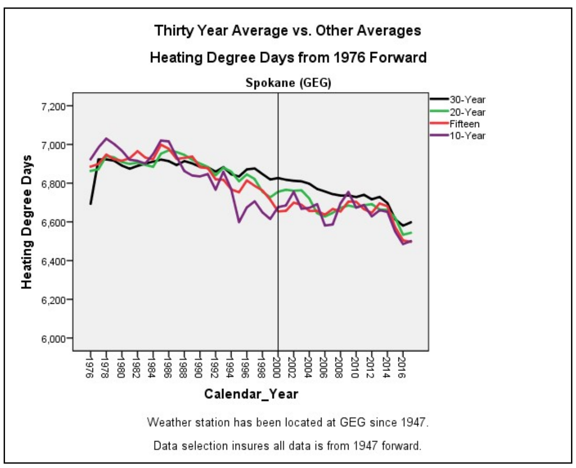

Figure 9-8. Thirty Year Average vs. Other Averages for HDD

An implication for Demand-Side Management is that the effect of going to a 20-year moving average will be to create stronger cost-effectiveness results for cooling measures and somewhat weaker cost-effectiveness results for heating measures.

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158 See also: Drury, Matt and Mallorie Gattie-Garza, “Climate Change and its Effect on Weather Data”. Pp, 9-1 to 9-11 in *Proceedings of the 2016 American Council for an Energy Efficient Economy Summer Study on Energy Efficiency in Buildings.* Washington, DC: ACEEE, 2016. Drury and Gattie-Garza suggest applying simple regression analysis to project HDD and CDD over the life of a DSM project rather than use backward looking weather normalization averages. Projections based on regression models may be more useful than weather normalization by means of backwards-looking moving averages.

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Section 10. Recommendations

(1) The decoupling mechanisms have worked as expected to stabilize revenue without impacting utility operations and energy efficiency programs. We also found no evidence of adverse impacts to any customer groups. We recommend the electric and natural gas mechanisms be continued and certain modifications be considered.

(2) If practical for Avista, move the decoupling tariff effective date up from November 1st to July 1st to substantially increase the likelihood that reported revenue will be collected within two years, as required by the Securities and Exchange Commission.

(3) Avista might consider adjusting the low-income "carve out" each year for inflation to keep its value more stable between rate cases.

(4) We have a sense that staffing is a bit thin compared with other utility clients with whom we recently have been engaged for projects. What works as a short-run cost savings may not work as well long-term. We recommend consideration of some additional hiring of some additional staff in Rates and in DSM (not short-term supplementary or temporary arrangements).

(5) We notice that as a cost savings measure, Avista has moved from a defined benefit pension system to a system that puts employees at individual risk in developing funding for retirement. We agree this will represent cost-savings in the short term. Although such change is currently viewed as normal in the industry, reflecting the market in this case may not be useful long-term. Thinking of the five most recent "crashes" including the recent "Great Recession", Avista might want to consider a plan that would enable some form of pension that places institutional strength between employees as individual "nano-investors" and market forces.

(6) Continue to work towards a possible low-income rate. Households in need of income to meet the expectations of American households prior to the income allocation reversal that began in the early 1970s, are likely about one-half of residential households (or at least 37.5%, as shown in the low-income appendix). A low-income rate would provide an additional tool to maintain service for all customers.

(7) In the low-income area, consider either moving to a higher level of rigor in evaluation and program administration by using the Self-Sufficiency standard; or use the 200% of the Federal Poverty Level as the program guideline for need for program payment assistance and weatherization services.

(8) Consider a redefinition of normal weather that moves away from the 30-year moving average to a 20-year moving average, and also maintain a moving average indicator for 15 years and 10 years to see how that behaves empirically, since "normal" has become a flow variable and it is rapidly getting warmer as a secular trend.

Avista Decoupling Evaluation

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May 27, 2022

Amanda Maxwell
Executive Director and Secretary
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, Washington 98503

Re: **Tariff WN U-28, Electric Service**
Electric Decoupling Rate Adjustment

Dear Ms. Maxwell:

Attached for electronic filing with the Commission is the following tariff sheet proposed to be effective August 1, 2022:

Seventh Revision Sheet 75 Canceling **Sixth Revision Sheet 75**

This filing is the "Electric Decoupling Rate Adjustment", filed in compliance with the Commission's Order No. 05 in Docket UE-140188 and Order No. 9 in Docket UE-190334. In Docket UE-140188, the Commission approved an electric decoupling mechanism for Avista for a five-year period. In Docket UE-190334, the Commission extended the mechanism for an additional five-year period and approved moving the effective date of the annual decoupling tariff revisions from November 1 to August 1. This filing amortizes the 2021 deferral balances over the period August 1, 2022 – July 31, 2023.

The purpose of the electric decoupling mechanism is to decouple the Company's Commission-authorized revenues from kilowatt-hour ("kWh") sales, such that the Company's revenues will be recognized based on the number of customers served under the applicable electric service schedules. The decoupling mechanism allows the Company to: 1) defer the difference between actual decoupling-related revenue received from customers through volumetric rates, and the decoupling-related revenue approved for recovery in the Company's last general rate case; and 2) file a tariff to surcharge or rebate, by rate group, the total deferred amount accumulated in the deferred revenue accounts for the prior January through December time period.

The proposed tariff reflects a rebate rate of 0.234 cents per kWh for the Residential Group served under Schedules 1 and 2, which is designed to rebate approximately $5.8 million to the Residential Group. The present rebate rate of 0.045 cents per kWh is presently designed to rebate to customers approximately $1.1 million. Therefore, the net overall change proposed for the Residential Group is a rate decrease of 0.189 cents per kWh, or a decrease of $4.7 million (2.0%) for the Residential Group customers.

In addition, the proposed tariff reflects a surcharge rate of 0.132 cents per kWh for the Non-Residential Group served under Schedules 11, 12, 13, 21, 22, 23, 31, and 32, which is designed to recover approximately $2.8 million from the Non-Residential Group. The present surcharge rate of 0.679 cents per kWh is presently designed to recover from customers approximately $14.1 million. Therefore, the net overall change proposed for the Residential Group is a rate decrease of 0.547 cents per kWh, or a decrease of $11.3 million (4.9%) for the Non-Residential Group customers.

	Expiring Present Decoupling Revenue	Proposed Decoupling Revenue	Proposed Decoupling Change
Residential Group	$(1,115,597)	$(5,801,102)	($4,685,506)
Non-Residential Group	$14,134,127	$2,747,724	$(11,386,402)

Residential Group Rate Determination

The Company recorded $5,123,505 in the rebate direction in deferred revenue for the electric Residential Group in 2021. The earnings test and the 3% incremental surcharge limitation, discussed later in this letter, had no impact on the 2021 electric balances. The proposed rebate rate of 0.234 cents per kWh is designed to rebate $5,801,102 to the Company's residential electric customers served under rate Schedules 1 and 2. The following table summarizes the components of the Company's request for recovery:

2021 Deferred Revenue	$(5,123,505)
Add: Earnings Sharing Adjustment	$0
Add: Prior Year Carryover Balance	$(224,670)
Add: Interest through 07/31/2023	$(187,264)
Add: Revenue Related Expense Adj.	$(265,663)
Total Requested Recovery	$(5,801,102)
Customer Surcharge Revenue	$(5,801,102)
Carryover Deferred Revenue	$0

Attachment A, page 1 shows the derivation of the proposed rebate rate to return the 2021 deferred revenue (including prior period unamortized deferred revenue), plus interest and revenue-related expenses, based on projected sales volumes for Schedules 1 and 2 during the surcharge/amortization period (August 2022 through July 2023). As identified in Tariff Schedule 75 under Step 7 of "Calculation of Monthly Deferral", interest on the deferred balance accrues at the quarterly rate published by the FERC.[1] If the proposed rebate is approved by the Commission, the 2021 deferral balance, less earnings sharing (if any), plus interest through July, will be transferred into a regulatory liability balancing account to be combined with the carryover balance approved for recovery in Docket UE-210378, Avista's 2021 Electric Rate Adjustment filing. The balance in the liability account will be reduced each month by the revenue rebated under the tariff.

Non-Residential Group Rate Determination

The Company recorded $2,389,111 in the surcharge direction in deferred revenue for the electric Non-Residential Group in 2021. The earnings test and the 3% incremental surcharge limitation, discussed later in this letter, had no impact on the 2021 electric balances. The proposed surcharge rate of 0.132 cents per kWh is designed to recover $2,747,724 from commercial and industrial customers served under rate Schedules 11, 12, 13, 21, 22, 23, 31, and 32. The following table summarizes the components of the Company's request for recovery:

2021 Deferred Revenue	$2,389,111
Add: Earnings Sharing Adjustment	$0
Add: Prior Year Carryover Balance	$148,270
Add: Interest through 07/31/2021	$86,597
Add: Revenue Related Expense Adj.	$123,746
Total Requested Recovery	$2,747,724
Customer Surcharge Revenue	$2,747,724
Carryover Deferred Revenue	$0

Attachment A, page 3 shows the derivation of the proposed surcharge rate to recover the 2021 deferred revenue (including prior period unamortized deferred revenue), plus interest and revenue-related expenses, based on projected sales volumes for Schedules 11, 12, 13, 21, 22, 23, 31, and 32 during the surcharge/amortization period (August 2022 through July 2023). As identified in Tariff Schedule 75 under Step 7 of "Calculation of Monthly Deferral", interest on the deferred balance accrues at the quarterly rate published by the FERC. If the proposed surcharge is approved by the Commission, the 2021 deferral balance, less earnings sharing (if any), plus interest through July, will be transferred into a regulatory asset balancing account to be combined with the residual balance approved for recovery in Docket UE-210378, Avista's 2021 Electric Decoupling Rate Adjustment filing. The balance in the account will be reduced each month by the revenue collected under the tariff.

Support showing the monthly calculation of the 2021 deferred revenue balances for both the Residential and Non-Residential Groups is provided as Attachment B. These calculations were also provided to the Commission in quarterly reports (see Docket UE-140188). The allowed decoupling baseline values that were updated when Docket UE-190334 rates became effective April 1, 2020 remained in effect through September 30, 2021. The allowed decoupling baseline

[1] The FERC effective interest rate was 3.25% in 2021 and 3.25% in Q1 and Q2 of 2022. The current rate of 3.25% has been used going forward as an estimate for purposes of this rate determination.

values were updated when the rates approved in Docket UE-200900 became effective October 1, 2021 and remained in effect for the remainder of 2021. Attachment B pages 1, 2, and 11 show the monthly deferral calculations for 2021, pages 3-6 are Docket UE-190334 authorized decoupling baseline values associated with 2021 customer rates through September 30, 2021 and pages 7-10 are Docket UE-200900 authorized decoupling base line values associated with the remainder of 2021.

Earnings Test

The decoupling mechanism is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues, normalized power supply costs and other normalizing adjustments. If the earnings test rate of return exceeds the allowed rate of return approved by the Commission, one-half of the revenue in excess of the rate of return will be shared with customers through the decoupling rate adjustment.

The 2021 Washington Electric Earnings Test sharing calculations are shown on page 6 of Attachment A.[2] The Earnings Test showed that the Company earned a 6.59% rate of return on a normalized basis in 2021 which does not exceed the allowed return of 7.19%.[3] Therefore, no earnings sharing adjustment is applied to the 2021 decoupling deferred balances.

3% Annual Rate Increase Test

Decoupling annual rate adjustment surcharges are subject to a 3% annual rate increase limitation. As described in Tariff Schedule 75 the 3% annual rate increase limitation "will be determined by dividing the incremental annual revenue to be collected (proposed surcharge revenue less present surcharge revenue) under this Schedule by the total "normalized" revenue for the two Rate Groups for the most recent January through December period. Normalized revenue is determined by multiplying the weather-corrected usage for the period by the present rates in effect. If the incremental amount of the proposed surcharge exceeds 3%, only a 3% incremental rate increase will be proposed. Any remaining deferred revenue will be carried over to the following year. There is no limit to the level of the decoupling rebate, and the reversal of any rebate rate would not be included in the 3% incremental surcharge test".

Revenue from 2021 normalized loads and customers calculated at the billing rates in effect since April 1, 2022 for the two rate groups are shown on line 1 of page 7 of Attachment A (these are the same values used to allocate the earnings sharing, if any, on lines 11 and 12 of page 6).

The rate necessary to recover the Residential Group rebate balance, including estimated interest and revenue related expenses as determined on page 1 of Attachment A (see line 20 - Preliminary Proposed Decoupling Rate), less the rebate rate presently in effect, would recover $4,685,506 less from customers (based on projected sales volumes for Schedules 1 and 2 during the

[2] The complete decoupling earnings test model is included as part of the electronic work papers to this filing.
[3] The allowed return was 7.19% for the rates in effect throughout 2021 as established Docket UE-190334.

surcharge/amortization period). Therefore, as shown on Attachment A, page 7, the 3% limitation does not affect the proposed residential rate.

The rate necessary to recover the Non-Residential Group surcharge balance, including estimated interest and revenue related expenses as determined on page 3 of Attachment A (see line 20 - Preliminary Proposed Decoupling Rate) less the surcharge rate presently in effect, would recover $11,386,402 less from customers (based on projected sales volumes for Schedules 11, 12, 13, 21, 22, 23, 31, and 32 during the surcharge/amortization period). Therefore, as shown on Attachment A, page 7, the 3% limitation does not affect the proposed non-residential rate.

Conclusion

In conclusion, Avista requests the Commission approve the proposed Schedule 75 rebate rate of 0.234 cents per kWh for the Residential Group and the proposed surcharge rate of 0.132 cents per kWh for the Non-Residential Group. The estimated annual revenue change associated with this filing is a decrease of approximately $16.1 million. Residential customers taking service on Schedule 1 and 2 using an average of 932 kilowatt hours per month would see their monthly bills change from $85.52 to $83.79, a decrease of $1.73, or 2.0%.

The Company has provided in this filing a copy of its customer notice which will be included as a bill insert in the June – July time frame. Please direct any questions on this matter to Joel Anderson at (509) 495-2811 or myself at (509) 495-4546.

Sincerely,

/s/ Joe Miller

Joe Miller
Senior Manager of Rates and Tariffs, Regulatory Affairs
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May 27, 2022

Amanda Maxwell
Executive Director and Secretary
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, WA 98503

Re: **Tariff WN U-29, Natural Gas Service**
Natural Gas Decoupling Rate Adjustment

Dear Ms. Maxwell:

Attached for electronic filing with the Commission is the following tariff sheet proposed to be effective August 1, 2022:

Eighth Revision Sheet 175 Canceling **Seventh Revision Sheet 175**

This filing is the "Natural Gas Decoupling Rate Adjustment", filed in compliance with the Commission's Order No. 05 in Docket UG-140189 and Order No. 9 in Docket UE-190335. In Docket UE-140188, the Commission approved a natural gas decoupling mechanism for Avista for a five-year period. In Docket UE-190335, the Commission extended the mechanism for an additional five-year period and approved moving the effective date of the annual decoupling tariff revisions from November 1 to August 1. This filing amortizes the 2021 deferral balances over the period August 1, 2022 – July 31, 2023.

The purpose of the natural gas decoupling mechanism is to decouple the Company's Commission-authorized revenues from therm sales, such that the Company's revenues will be recognized based on the number of customers served under the applicable natural gas service schedules. The decoupling mechanism allows the Company to: 1) defer the difference between actual decoupling-related revenue received from customers through volumetric rates, and the decoupling-related revenue approved for recovery in the Company's last general rate case; and 2) file a tariff to surcharge or rebate, by rate group, the total deferred amount accumulated in the deferred revenue accounts for the prior January through December time period.

The proposed tariff reflects a surcharge of 3.899 cents per therm for the Residential Group served under Schedules 101 and 102, which is designed to recover approximately $5.4 million from the Residential Group. The present surcharge rate of 0.925 cents per therm is presently designed to recover from customers approximately $1.3 million. Therefore, the net overall increase proposed for the Residential Group is 2.974 cents per therm, or an increase of approximately $4.1 million or 3.0% from the Residential Group customers.

In addition, the proposed tariff reflects a surcharge of 2.866 cents per therm for the Non-Residential Group served under Schedules 111, 112, 116, and 131, which is designed to recover approximately $1.7 million from the Non-Residential Group. The present surcharge rate of 0.813 cents per therm is presently designed to recover from applicable customers approximately $0.5 million. Therefore, the net overall increase proposed for the Non-Residential Group is a rate increase of 2.053 cents per therm, or an increase of approximately $1.2 million or 3.0% for the Non-Residential Group customers.

	Expiring Present Decoupling Revenue	Proposed Decoupling Revenue	Proposed Decoupling Increase
Residential Group	$1,276,010	$5,378,553	$4,102,543
Non-Residential Group	$476,613	$1,680,164	$1,203,550

Residential Group Rate Determination

The Company recorded $6,559,458 in the surcharge direction in deferred revenue for the natural gas Residential Group in 2021. The 3% incremental surcharge limitation, discussed later in this letter, resulted in a $1,642,757 reduction of the 2021 deferral surcharge. The proposed surcharge rate of 3.899 cents per therm is designed to recover $5,378,553 from the Company's residential natural gas customers served under rate Schedules 101 and 102. The following table summarizes the components of the Company's requested surcharge:

2021 Deferred Revenue	$6,559,458
Add: Earnings Sharing/DSM Adjustment	($57,986)
Add: Prior Year Carryover Balance	$24,802
Add: Interest through 07/31/2023	$266,044
Add: Revenue Related Expense Adj.	$228,992
Total Requested Recovery	$5,378,553
Customer Surcharge Revenue	$5,378,553
Carryover Deferred Revenue	$1,642,757

Attachment A, page 1 shows the derivation of the proposed surcharge rate to recover the 2021 deferred revenue (including prior period unamortized deferred revenue) plus interest and revenue-related expenses, based on projected sales volumes for Schedules 101 and 102 during the surcharge/amortization period (August 2022 through July 2023). As identified in Tariff Schedule 175 under Step 6 of "Calculation of Monthly Deferral", interest on the deferred balance accrues at the quarterly rate published by the FERC.[1] If the proposed surcharge is approved by the Commission, the 2021 deferral balance, less earnings sharing (if any), plus interest through July, will be transferred into a regulatory asset balancing account along with any residual regulatory asset balance approved for recovery in Docket UG-210379, Avista's 2021 Natural Gas Decoupling Rate Adjustment filing. The balance in the account will be reduced each month by the revenue collected under the tariff.

Non-Residential Group Rate Determination

The Company recorded $2,400,734 in the surcharge direction in deferred revenue for the natural gas Non-Residential Group in 2021. The 3% incremental surcharge limitation, discussed later in this letter, resulted in a $894,261 reduction of the 2021 deferral surcharge. The proposed surcharge rate of 2.866 cents per therm is designed to recover $1,680,164 from commercial and industrial customers served under rate Schedules 111, 112, 116, and 131. The following table summarizes the components of the Company's request for recovery:

2021 Deferred Revenue	$2,400,734
Add: Earnings Sharing/DSM Adjustment	($17,014)
Add: Prior Year Carryover Balance	$18,077
Add: Interest through 07/31/2023	$101,106
Add: Revenue Related Expense Adj.	$71,521
Total Requested Recovery	$1,680,164
Customer Surcharge Revenue	$1,680,164
Carryover Deferred Revenue	$894,261

Attachment A, page 3 shows the derivation of the proposed surcharge rate to recover the 2021 deferred revenue (including prior period unamortized deferred revenue) plus interest and revenue-related expenses, based on projected sales volumes for Schedules 111, 112, 116, and 131 during the surcharge/amortization period (August 2022 through July 2023). As identified in Tariff Schedule 175 under Step 6 of "Calculation of Monthly Deferral", interest on the deferred balance accrues at the quarterly rate published by the FERC. If the proposed surcharge is approved by the Commission, the 2021 deferral balance, less earnings sharing (if any), plus interest through July, will be transferred into a regulatory asset balancing account to be combined with any residual balance approved for recovery in Docket UG-210379, Avista's 2021 Natural Gas Decoupling Rate Adjustment filing. The balance in the account will be reduced each month by the revenue collected under the tariff.

Support showing the monthly calculation of the 2021 deferred revenue balances for both the Residential and Non-Residential Groups is provided as Attachment B. These calculations were also provided to the Commission in quarterly reports (see Docket UG-140189). The allowed decoupling baseline values that were updated when Docket UG-190335 rates became effective

[1] The FERC effective interest rate was 3.25% in 2021 and 3.25% in Q1 and Q2 of 2022. The current rate of 3.25% has been used going forward as an estimate for purposes of this rate determination.

April 1, 2020 remained in effect through September 30, 2021. The allowed decoupling baseline values were updated when the rates approved in Docket UG-200901 became effective October 1, 2021 and remained in effect for the remainder of 2021. Attachment B page 1, 2 and 11 shows the monthly deferral calculations for 2021, pages 2 – 5 and pages 7 – 9 are Docket UG-190335 and UG-200901, respectively, authorized decoupling baseline values associated with 2021 customer rates.

Earnings Test

The decoupling mechanism is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues and various normalizing adjustments. If the earnings test rate of return exceeds the allowed rate of return approved by the Commission, one-half of the revenue in excess of the rate of return will be shared with customers through the decoupling rate adjustment.

The 2021 Washington Natural Gas Earnings Test sharing calculations are shown on page 6 of Attachment A.[2] The Earnings Test showed that the Company earned a 7.10% rate of return on a normalized basis in 2021 which does not exceed the allowed return of 7.19%.[3] Therefore, no earnings sharing adjustment is applied to the 2021 decoupling deferred balances.

Natural Gas Energy Efficiency Adjustment

In Order 09 in Docket UG-190335, the Commission approved Avista's request to institute a 5 percent conservation target for the natural gas decoupling mechanism. In 2021, Avista achieved 94% of its adjusted natural gas conservation target (that target including the additional 5 percent target above the planned 2021 IRP target). Consistent with the Commission's order, Avista has applied a $75,000 below-the-line natural gas decoupling adjustment to its 2021 results, allocating that adjustment to the Residential and Non-Residential Group on a percent of revenue basis.

3% Annual Rate Increase Test

Decoupling annual rate adjustment surcharges are subject to a 3% annual rate increase limitation. There is no limit to rebate rate adjustments. As described in Tariff Schedule 175 the 3% annual rate increase limitation "will be determined by dividing the incremental annual revenue to be collected (proposed surcharge revenue less present surcharge revenue) under this Schedule by the total "normalized" revenue for the two Rate Groups for the most recent January through December time period. Normalized revenue is determined by multiplying the weather-corrected usage for the period by the present rates in effect. If the incremental amount of the proposed surcharge exceeds 3%, only a 3% incremental rate increase will be proposed and any remaining deferred revenue will be carried over to the following year. There is no limit to the level of the decoupling rebate, and the reversal of any rebate would not be included in the 3% incremental surcharge test".

[2] The complete decoupling earnings test model is included as part of the electronic work papers to this filing.
[3] The allowed return was 7.19% for the rates in effect throughout 2021 as established by Docket UG-190335.

Revenue from 2021 normalized loads and customers calculated at the billing rates in effect since November 1, 2021 for the two rate groups are shown on line 1 of page 7 of Attachment A (these are the same values used to allocate the earnings sharing and DSM adjustment, if any, on lines 11 and 12 of page 6).

The proposed Residential Group rate results in a surcharge of 4.24% and therefore exceeds the 3% limitation. A reduction of $1.7 million was made to the decoupling revenue for recovery to adjust the surcharge from 4.24% to 3% as shown on Page 7 of attachment A.

The proposed Non-Residential Group rate results in a surcharge of 5.29% and therefore exceeds the 3% limitation. A reduction of $0.9 million was made to the decoupling revenue for recovery to adjust the surcharge from 5.29% to 3% as shown on Page 7 of attachment A.

Conclusion

In conclusion, Avista requests the Commission approve the proposed Schedule 175 surcharge rate of 3.899 cents per therm for the Residential Group and the proposed surcharge rate of 2.866 cents per therm for the Non-Residential Group. The estimated annual revenue change associated with this filing is an increase of approximately $5.3 million ($4.1 million Residential and $1.2 million Non-Residential). Residential customers taking service on Schedule 101 using an average of 67 therms would see their monthly bills change from $64.86 to $66.85, an increase of $1.99, or 3%.

The Company has provided in this filing a copy of its customer notice which will be included as a bill insert in the June – July time frame. Please direct any questions on this matter to Joel Anderson at (509) 495-2811 or myself at (509) 495-4546.

Sincerely,

/s/ Joe Miller

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Senior Manager of Rates and Tariffs, Regulatory Affairs
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