Witness OCS – 5D COS/RD

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of	**)**	
Rocky Mountain Power for Authority	**)**	**Docket No. 13-035-184**
to Increase its Retail Electric Utility	**)**	**Direct COS/RD**
Service Rates in Utah and for	**)**	**Testimony of**
Approval of Its Proposed Electric	**)**	**Daniel E. Gimble**
Service Schedules and Electric	**)**	**For the Office of**
Service Regulations	**)**	**Consumer Services**

May 22, 2014

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND YOUR BUSINESS ADDRESS.

A. My name is Daniel E. Gimble. I am a manager with the Office of Consumer Services. My business address is 160 E. 300 S. Rm. 201, Salt Lake City, Utah.

Q. PLEASE DISCUSS YOUR EDUCATION AND QUALIFICATIONS.

A. I have a B.A. degree with honors in economics and history from Western Michigan University. I also have an M.A degree in economics from the same university. I completed course work towards a Ph.D. in economics at the University of Utah. In 1985, I joined the Utah Public Service Commission (Commission) Staff and in 1990 was hired by the Office of Consumer Services (Office). In my time with the Office, I have worked in various capacities and have been a manager since 2003.

Q. HAVE YOU APPEARED AS A WITNESS BEFORE THIS COMMISSION IN PRIOR CASES INVOLVING ROCKY MOUNTAIN POWER OR OTHER UTILITIES?

A. Yes. Since 1991 I have testified numerous times in major cases involving Rocky Mountain Power (the Company or RMP) and other utilities providing service in Utah. These cases include general rate cases, merger and acquisition dockets, power cost proceedings, avoided cost cases, integrated resource plan (IRP) cases, EBA proceedings, major plant addition cases and the sale of Qwest's Dex (Yellow Pages) asset. I filed testimony supporting the Office's cost-of-service, rate spread and rate design recommendations in the last five RMP general rate cases (GRCs).[1]

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

A. My testimony does the following:

- Presents the Office's cost-of-service recommendations;
- Presents the Office's rate spread proposal;

[1] Docket Nos. 07-035-93, 08-035-38, 09-035-23, 10-035-124 and 11-035-200.

- Responds to the Company's rate spread proposal;
- Presents the Office's rate design recommendations;
- Presents the Office's recommendations on marginal cost studies and related information;
- Presents the Office's recommendations on the Company's newly-proposed facilities charge for residential net metering customers; and
- Addresses the Company's proposed Schedule 31 rates.

Q. ARE THE OFFICE'S RECOMMENDATIONS IN YOUR DIRECT TESTIMONY SUPPORTED BY OTHER OFFICE WITNESSES?

A. Yes. Mr. Paul Chernick, a principal with Resource Insights, Inc., is filing expert direct testimony on the Company's COS Study and recommends a number of improvements to that Study. Mr. Danny Martinez, a utility analyst with the Office, is filing direct testimony supporting the Office's residential rate design proposals in this proceeding.

II. <u>SUMMARY OF RECOMMENDATIONS</u>

Q. PLEASE SUMMARIZE THE OFFICE'S COS RECOMMENDATIONS.

A. The Commission should adopt the improvements to the Company's COS Study, as recommended by Mr. Chernick in his direct testimony. These proposed improvements are as follows:

- Classify 75% of the Company's steam (coal) generation plant and associated expenses as energy-related;
- Classify 98% of the Company's wind generation plant and associated expenses as energy-related;
- Classify 50% of the Company's hydro generation plant and associated expenses as energy-related;
- Classify at least 35% of the Company's other generation plant (gas CCCTs and SCCTs) and associated expenses as energy-related; and
- Classify at least 66% of firm non-seasonal purchases, which include firm wind purchases, as energy-related.

As discussed in Mr. Chernick's direct testimony, the Commission should also continue to require the Company to use a 12-CP factor to allocate demand-related generation plant and associated expenses and the appropriate 12-CP factor is the un-weighted version.

Lastly, based on Mr. Chernick's analysis, the Office proposes that the allocation of overhead and general costs be addressed prior to the next GRC, in a technical conference format open to all interested parties. While the Office could meet separately with the Company to discuss cost drivers underlying the allocation of overhead and general accounts, we believe that all interested parties could benefit from a discussion on this issue.

Q. PLEASE SUMMARIZE THE OFFICE'S RATE SPREAD RECOMMENDATONS.

A. The Commission should order a rate spread that brings the retail rate schedules closer to paying rates that recover their estimated cost of service. The Office has developed a fair and reasonable rate spread proposal to accomplish that objective. At a revenue requirement increase between $11.0 million and the Company's requested $71.3 million, the Office's proposal is:

- Residential Schedules 1, 2, 3, and General Service Schedule 8 should receive a rate increase at the jurisdictional average rate increase;
- Irrigation Schedule 10 should receive an increase of 2.0 percentage points above the jurisdictional average rate increase;
- Commercial Schedules 6 and 23 should receive a rate changes 3.0 and 2.0 percentage points, respectively below the jurisdictional average rate increase;
- Large Industrial Schedule 9 should receive a rate increase 4.0 percentage points above the jurisdictional average rate increase;
- All special contract customers should receive rate increases consistent with their individual contract terms; and

- Lighting Schedules 7, 11, 12, and 15 (MOL)[2] should receive rate changes that range between 2.75 and 5.75 percentage points below the jurisdictional average rate increase.

The Office also proposes that the following rate spread decision rules be applied in this case:

- At any ordered increase in revenue requirement at or above $11.0 million, the Office's proposed percentage point differences from the jurisdictional average would remain constant for the major rate schedules. Maintaining these percentage point relationships among classes will help to rebalance rates between the classes that are near or above cost-of-service and Schedule 9, which continues its trend of underperforming.
- At any ordered increase in revenue requirement between $0 and $11.0 million, the Commission should give the vast majority of the increase to Schedule 9. Under this scenario, Schedules 1, 8 and 10 should receive very small rate increases with the increase for 10 slightly higher than the other two schedules and Schedules 6 and 23, along with the lighting schedules, should receive rate decreases. .
- Any ordered decrease in revenue requirement should be apportioned entirely among classes that have a history of over-performing; namely Commercial Schedules 6 and 23 and Lighting Schedules 7, 11, 12 and 15M.

Q. PLEASE SUMMARIZE THE OFFICE'S RATE DESIGN RECOMMENDATONS.

A. The Office's rate design recommendations are as follows:

- Schedules 1, 2 and 3 (Residential):
    - o Increase the monthly single-phase customer charge from $5.00 to $6.00;

[2]MOL = Metered Outdoor Lighting.

  - Increase the monthly three-phase customer charge from $10.00 to $12.00;
  - Increase the residential minimum bill from $7.00 to $10.00;
  - Leave the two-block non-summer and three-block summer energy rate structure unchanged;
  - At revenue requirement increases above $31 million, the second block non-summer energy rate should be increased to more closely align it to the second block summer energy rate. Any remaining revenue should generally be applied proportionately through increases to the second and third (summer only) energy block rates;
  - Increase the monthly Low Income Lifeline Credit (LILC) on Schedule 3 from $11.00 to $12.60.
- Schedules 10 and 23 (Irrigation and Small Commercial):
  The Office recommends no changes to the Company's rate design proposals for Schedules 10 and 23.
- Schedule 135 (Net Metering):
  The Office recommends a new net metering facilities charge of $1.60/kW be applied to the monthly bills of residential net metering customers.

Q: PLEASE SUMMARIZE THE OFFICE'S POSITION ON THE COMPANY'S PROPOSED CHANGES TO SCHEDULE 31 RATES.

A: The Office generally agrees with the Company that changes to Schedule 31 rates are needed to better align those rates with costs incurred by the Company to provide services (e.g., back-up, supplementary, etc.) to large customers. As explained in greater detail in Mr. Chernick's testimony, the Office has two initial concerns with the Company's proposed rate design for Schedule 31 customers. First, the Company's proposed back-up rate may provide Schedule 31 customers an inappropriate discount compared to the firm service rate. Second, the Company's proposal provides limited incentive for a Schedule 31 customer that has a short outage (perhaps for overnight maintenance) to bring the generation back on-line before system loads peak on a given day.

Q. YOU INDICATED ABOVE THAT THESE ARE THE OFFICE'S PRELIMINARY CONCERNS? PLEASE EXPLAIN.

A. We anticipate interveners with industrial customers directly impacted by the Company's proposed rate changes will have alternative proposals. After reviewing those proposals, the Office may have additional concerns and recommendations on the Company's proposed Schedule 31 rates.

III. <u>RATE SPREAD</u>

Office's Rate Spread Proposal

Q. A COMMISSION ORDER ON REVENUE REQUIREMENT WILL NOT BE AVAILABLE BEFORE THE FILING OF SPREAD PROPOSALS IN THIS PROCEEDING. WHAT REVENUE NUMBERS DID THE OFFICE USE TO DEVELOP ITS RATE SPREAD PROPOSAL?

A. The Office's rate spread proposal is presented in terms of a number of hypothetical changes in revenue requirement ranging from the Company's requested $71.3 million increase to the Office's recommendation that revenues be decreased by $4.6 million In addition, the Office has developed rate spread <u>decision rules</u> that the Commission can use as a guide for making spread decisions in this proceeding. These decision rules are tied to specific changes in revenue requirement ordered by the Commission and are described below.

Q. PLEASE PROVIDE THE OFFICE'S SPECIFIC RATE SPREAD PROPOSAL AND SPREAD DECISION RULES FOR THIS GRC.

A. The Office's specific rate spread proposal for revenue increases at or above $11.0 million is set forth in my Direct Exhibit OCS 5.1, pages 1 - 4, and is as follows:

- Residential Schedules 1, 2, 3, and General Service Schedule 8 should receive a rate increase at the jurisdictional average rate increase;

- Irrigation Schedule 10 should receive a rate increase 2.0 percentage points above the jurisdictional average rate increase;
- Commercial Schedules 6 and 23 should receive rate changes 3.0 and 2.0 percentage points, respectively below the jurisdictional average rate increase;
- Large Industrial Schedule 9 should receive a rate increase 4.0 percentage points above the jurisdictional average rate increase;
- All special contract customers should receive rate increases consistent with their individual contract terms; and
- Lighting Schedules 7, 11, 12, and 15M[3] should receive rate decreases at any ordered change in revenue requirement. Since these schedules have very high returns in the current GRC, the Office has used these schedules for balancing purposes in our spread proposal. Thus, the percentage point changes for the Lighting Schedules range from 2.75 to 5.75 below the jurisdictional average rate increase.

The Office also proposes that the following rate spread decision rules be applied in this GRC:

- At any ordered increase in revenue requirement at or above $11 million, the Office's proposed percentage point differences from the jurisdictional average would remain constant for the major rate schedules. Maintaining these percentage point relationships among classes will help to rebalance rates between the classes that are near or above cost-of-service and Schedule 9, which continues its trend of underperforming.
- At any ordered increase in revenue requirement between 0 and $11 million, the Commission should give the vast majority of the increase to Schedule 9. Under this scenario, Schedules 1, 8 and 10 should receive very small rate increases with the increase for 10 slightly higher than the other two schedules and Schedules 6 and 23, along with the lighting schedules, should receive rate decreases. .

[3]Schedule 15M is the Metered Outdoor Lighting Schedule.

- Any ordered decrease in revenue requirement should be apportioned entirely among classes that have a history of over-performing; namely Commercial Schedules 6 and 23 and Lighting Schedules 7, 11, 12 and 15M.

Q. WHY SHOULD THE COMMISSION FIND THE OFFICE'S RATE SPREAD PROPOSAL PREFERABLE TO THAT SUBMITTED BY THE COMPANY?

A. As I will discuss in more detail in this section of my direct testimony, the Office's rate spread proposal takes into account the improvements recommended by its expert, Mr. Chernick, to the Company's COS Study, better reflects COS results than the Company's proposal and moves Schedule 9, a chronically underperforming class, closer to paying rates that cover cost-of-service.

Q. HAVE YOU PREPARED TABLES THAT SHOWS THE IMPACT OF THE OFFICE'S SPREAD PROPOSAL ON THE MAJOR RATE SCHEDULES?

A. Yes. Tables 1 - 4 below show the Office's rate spread for the major rate schedules at the following hypothetical values: the Company's requested revenue requirement increase of $71.3 million, $51.0 million, $31.0 million and $11.0 million.[4] For purposes of comparison, these tables also show the Company's spread proposal at these revenue requirement numbers.[5]

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[4]"JA" in the tables refers to jurisdictional average. The jurisdictional average numbers presented are approximate based on a slight rounding to achieve the Company's proposed midpoint values at different revenue requirement numbers.

[5] Regarding the Company's spread proposal shown in all tables, the same percentage point relationships discussed by Ms. Steward in her direct testimony are maintained. At any revenue requirement number less than $71.3 million, the Company could possibly alter its rate spread proposal to accomplish different spread objectives. Thus, the comparison of the Office and Company spread proposals at different revenue requirement levels is for illustrative purposes only.

Table 1: $71.3 Million RR Increase

Retail Classes	Schedules	OCS Rate Spread @ $71.3 M RR JA Inc. = 3.86%	RMP Rate Spread @ $71.3 M RR JA Inc. = 3.86%
Residential	1, 2, 3	3.86%	4.86%
Small Commercial	23	2.86%	2.86%
Large Commercial	6	1.86%	1.86%
Gen. Serv. (> 1 MW)	8	3.86%	3.86%
Large Industrial	9	7.86%	5.86%
Irrigation	10	5.86%	5.86%

Table 2: $51.0 Million RR Increase

Retail Classes	Schedules	OCS Rate Spread @ $51.0 M RR JA Inc. = 2.75%	RMP Rate Spread @ $51.0 M RR JA Inc. = 2.75%
Residential	1, 2, 3	2.75%	3.75%
Small Commercial	23	1.75%	1.75%
Large Commercial	6	0.75%	0.75%
Gen. Serv. (> 1 MW)	8	2.75%	2.75%

Large Industrial	9	6.75%	4.75%
Irrigation	10	4.75%	4.75%

Table 3: $31.0 Million RR Increase

Retail Classes	Schedules	OCS Rate Spread @ $31.0 M RR JA Inc. = 1.66%	RMP Rate Spread @ $31.0 M RR JA Inc. = 1.66%
Residential	1, 2, 3	1.66%	2.66%
Small Commercial	23	0.66%	0.66%
Large Commercial	6	(0.34%)	(0.34%)
Gen. Serv. (> 1 MW)	8	1.66%	1.66%
Large Industrial	9	5.66%	3.66%
Irrigation	10	3.66%	3.66%

Table 4: $11.0 Million RR Increase

Retail Classes	Schedules	OCS Rate Spread @ $11.0 M RR JA Inc. = 0.57%	RMP Rate Spread @ $11.0 M RR JA Inc. = 0.57%
Residential	1, 2, 3	0.57%	1.57%
Small Commercial	23	(0.43)%	(0.43)%
Large Commercial	6	(1.43%)	(1.43%)
Gen. Serv. (> 1 MW)	8	0.57%	0.57%

Large Industrial	9	4.57%	2.57%
Irrigation	10	2.57%	2.57%

Q. PLEASE EXPLAIN THE BASIS FOR THE OFFICE'S RATE SPREAD PROPOSAL.

A. The Office considered a number of factors in developing its rate spread proposal. The Office examined the rate of return performance for each rate schedule, as presented by the Company in its current COS Study.[6] We performed this review in the context of the returns for individual rate schedules over the last seven GRCs. Examining the returns across multiple cases helped to determine which of the major classes consistently produced sufficient revenue to cover estimated cost-of-service. The Office also took into account the improvements to the Company's COS Study recommended by its expert Mr. Chernick.

Evaluation of Class Returns

Q. PLEASE DISCUSS THE OFFICE'S EVALUATION OF CLASS RETURNS.

A. Table 5 below is a comparison of the class returns over the past seven GRCs, including the current proceeding.[7] If a rate schedule is showing a return of 1.00 (unity), this means that schedule is producing sufficient revenue to cover estimated costs. Class returns above or below 1.00 means that a rate schedule is producing either a revenue surplus or deficiency. In the current GRC, the Company's COS results indicate that the commercial schedules have the strongest returns, the residential schedule's return is about the same as the last GRC, the return for the irrigation schedule is improved and the large industrial schedule continues to have a very poor return.

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[6] Direct Exhibit RMP (JRS-1) includes a class rate of return index, which shows the calculated revenue deficiency or excess compared to the estimated cost for each class. Page 1 of Exhibit (JRS-1) shows Class COS results on a revenue neutral basis. Page 2 of the exhibit shows Class COS results per the Company's requested revenue requirement increase of $76.3 million.

[7] The class returns were taken from the summary table of Class COS results prepared by the Company's COS witnesses (Paice, Steward) for each of the past six and current GRCs. These include the following dockets: 06-035-21; 07-035-93; 08-035-38; 09-035-23; 10-035-124; 11-035-200; and 13-035-184.

Table 5

Rate Schedule	2006	2007	2008	2009	2010	2011	2013
Sch. 1	1.00	1.05	1.23	1.16	0.95	0.93	0.91
Sch. 23	1.18	0.84	1.15	1.01	1.21	1.24	1.13
Sch. 6	1.31	1.23	0.90	1.03	1.23	1.18	1.23
Sch. 8	1.00	1.01	0.97	0.94	0.97	1.06	1.04
Sch. 9	0.62	0.77	0.68	0.69	0.71	0.77	0.75
Sch. 10	0.29	0.17	0.32	0.43	0.72	0.79	0.85

As shown in Table 5, the residential and small industrial (Schedule 8) schedules have consistently produced satisfactory returns and the commercial schedules have consistently produced strong returns in most of these GRCs. In addition, the irrigation schedule's return has substantially improved over the past six GRCs, increasing from 0.17 in 2007 to .85 in 2013. By contrast, the large industrial rate schedule has failed to produce adequate returns in each of the past six and current GRCs and the approved rates have resulted in a large and persistent revenue deficiency.

Q. PLEASE EXPLAIN WHY THE INFORMATION INCLUDED IN TABLE 5 CONTINUES TO BE RELEVANT TO THE COMMISSION'S DECISION ON RATE SPREAD IN THIS PROCEEDING.

A. The returns in the current GRC represent a snapshot in time and should not be the only evidence considered in developing a fair and reasonable rate spread proposal. The seven-year history of class returns in Table 5 shows which classes have consistently been strong performers versus classes such as large industrial that have underperformed and continue to pay rates that fall far short of covering costs. The Office has presented this information in recent GRCs and the Commission relied on it in making its spread decision the last time rate spread was contested.[8] In making its rate spread decision in this proceeding, the Commission should once again rely on this information to evaluate past with current class performance.

Q. SHOULD THE COMMISSION BE ESPECIALLY CONCERNED ABOUT THE RETURNS SHOWN IN TABLE 5 FOR SCHEDULE 9?

A. Yes. The rates paid by Schedule 9 customers have been significantly below cost-of-service in each of the past six GRCs and the situation remains unchanged in current proceeding. According to its filed COS Study, the Company estimates that the revenue deficiency for Schedule 9 is $34.3 million at the Company's original $76.3 million rate request. Therefore, the Commission should remedy the chronic revenue shortfall for Schedule 9 by setting rates that move this class closer to cost-of-service. Absent a significant rebalancing of rates for Schedule 9, this class will continue to be unfairly subsidized by the other retail rate classes.

Q. DOES THE OFFICE'S PROPOSED RATE INCREASE FOR SCHEDULE 9 MOVE THE LARGE INDUSTRIAL CLASS ALL THE WAY TO COST-OF-SERVICE?

A. No. According to the Company's COS Study, a rate increase of 12.5% (at its filed $76.3 million revenue increase) would be necessary for Schedule 9 revenues to equal the Company's estimated cost-of-service.[9] While the Office's recommended rate increase for Schedule 9 represents a significant step in

[8] Utah Commission Order, Docket 09-035-23, page 148.

[9]Even on a revenue neutral basis ($0 revenue requirement increase), Schedule 9 would require a 5.3% rate increase to be at cost-of-service based on the Company's COS Study. This rate increase percentage would be even higher when incorporating the COS improvements proposed by Mr. Chernick.

aligning revenue with costs for this customer class, a revenue deficiency would still remain. Therefore, there is an aspect of gradualism in the Office's spread proposal related to Schedule 9.

Improvements to the Company's COS Study

Q. WHAT ADDITIONAL INFORMATION DID THE OFFICE CONSIDER IN DEVELOPING ITS RATE SPREAD PROPOSAL?

A. The Office considered the specific improvements recommended by Mr. Chernick to the Company's COS Study and the resulting impacts on individual class returns. In his critique of the Company's COS Study, Mr. Chernick recommends the following improvements to the Study:

- Classify 75% of the Company's steam (coal) generation plant and associated expenses as energy-related;
- Classify 98% of the Company's wind generation plant and associated expenses as energy-related;
- Classify 50% of the Company's hydro generation plant and associated expenses as energy-related;
- Classify at least 35% of the Company's other generation plant (gas CCCTs and SCCTs) and associated expenses as energy-related; and
- Classify at least 66% of firm non-seasonal purchases, which include firm wind purchases, as energy-related.

The impacts on the major rate schedules from Mr. Chernick's proposed improvements to the Company's COS Study are shown in Table 7 (page 40) of his direct testimony. When combined together, these proposed improvements increase the Company's reported returns for Schedule 1 and 23, leaves the return for Schedule 6 the same, and lowers the returns for Schedules 8, 9 and 10. In particular, the return for Schedule 1 increases from 0.91 to 1.02 and the return for Schedule 9 decreases from .75 to .60. Even if the Commission only decides to fix the disparate treatment of firm non-seasonal purchases versus

Company resources in the COS Study, this change alone would increase Schedule 1's return to almost .95.

Response to the Company's Rate Spread Proposal

Q. HOW DOES THE OFFICE'S PROPOSAL COMPARE TO THE COMPANY'S RATE SPREAD PROPOSAL?

A. In general, the Office's rate spread proposal is directionally consistent with the Company's proposal. Nevertheless, there are some notable differences between the two proposals involving Schedules 1, 9 and 10. These differences are discussed below.

Q. PLEASE EXPLAIN THE DIFFERENCES BETWEEN THE COMPANY'S AND OFFICE'S SPREAD PROPOSALS FOR RESIDENTIAL SCHEDULE 1.

A. The Company proposes a higher increase (one percentage point above its calculated mid-point) for Residential Schedule 1 based on its COS study results. However, as I discussed earlier in my direct testimony, Schedule 1 has produced relatively strong returns in past COS studies and the improvements to the Company's filed COS Study recommended by Mr. Chernick increases the estimated return for Schedule 1 from .91 to 1.02. The Office considers a return that falls between .95 and 1.05 to be close enough to 1.00 (revenues = costs) for a rate schedule to receive the jurisdictional average increase. The Office's adjusted return of 1.02 for Schedule 1 falls in this .95 - 1.05 range.

Q. PLEASE EXPLAIN THE DIFFERENCES BETWEEN THE COMPANY'S AND OFFICE'S SPREAD PROPOSALS FOR SCHEDULES 9 AND 10.

A. While the Company calculated a much higher return for Schedule 10 (.85) than Schedule 9 (.75) in its filed COS Study, it inexplicably proposes the same 6.1% rate increase for each schedule. Conversely, the Office appropriately recognizes the steady increase in Schedule 10's reported return over the past six rate cases and the relatively higher return for Schedule 10 compared to Schedule 9 in the current case. This relationship between these two schedules' returns is maintained even if the Commission adopts the improvements to the Company's COS Study proposed by Mr. Chernick. Thus, the Office has appropriately separated these two rate schedules and developed different rate spread recommendations.

Q. WHAT ADDITIONAL INFORMATION DID THE OFFICE RELY ON IN MAKING ITS SPREAD RECOMMENDATIONS FOR SCHEDULES 9 AND 10?

A. As shown in Table 6 below, Schedules 9 and 10 have essentially received the same increases in general rates over the past three GRCs. Despite these very similar increases in general rates since 2009, the reported returns for Schedule 9 remain stagnant compared to the progressively higher returns for Schedule 10. This is illustrated in Table 7 below.

Table 6

General Rate Increases for Schedules 9 and 10

Docket Number	09-035-23	10-35-124	11-035-200[10]	Total
Sch. 9 (Lg. Ind.)	3.52%	7.3%	9.15%	19.97%
Sch. 10 (Irrig.)	3.52%	7.1%	9.15%	19.95%

Table 7

Company COS Results for Schedules 9 and 10

Docket Number	09-035-23	10-35-124	11-035-200	13-035-184
Sch. 9 (Lg. Ind.)	0.69	0.71	0.77	0.75
Sch. 10 (Irrig.)	0.43	0.72	0.79	0.85

[10]In Docket 11-035-200, revenue increases for all classes were implemented in two stages: a Step 1 increase on October 10, 2012 and a Step 2 increase on September 1, 2013. Schedules 9 and 10 both received identical Step 1 and 2 increases of 6.07% and 3.08%, respectively.

Q. WHAT SHOULD THE COMMISSION CONCLUDE BASED ON THE INFORMATION PRESENTED IN TABLES 6 AND 7?

A. Since 2009, the Company's COS results clearly indicate that Schedule 10 has responded to rate increases with increasingly higher returns whereas Schedule 9's return remains virtually unchanged. This represents additional evidence that the Commission can rely on to make a finding that these two schedules need to be treated separately for ratemaking purposes. Specifically, Schedule 9 requires a higher rate increase in the current proceeding to move that class towards meeting a principal COS objective that all classes should pay cost-based rates.

IV. <u>RATE DESIGN</u>

Residential Schedule 3 - Low Income Lifeline Credit (LILC)

Q: PLEASE SUMMARIZE THE COMPANY'S PROPOSAL REGARDING THE RESIDENTIAL LILC.

A. The Company proposes increasing the monthly LILC from $11.00 to $12.60 to reflect increases in residential rates since the LILC was last changed in 2009. The Company states that the current collection rate under Schedule 91 provides adequate revenue to support the proposed $1.60/month increase in the LILC and that it will monitor balances and, if needed, recommend future changes to the collection rate.

Q. IS THERE EVIDENCE THAT THE MONTHLY LILC CAN BE INCREASED BY $1.60/MONTH WITHOUT INCREASING THE SCHEDULE 91 COLLECTION RATE?

A. Yes. The Company's January 29, 2014 Report on the Low Income Lifeline Program indicates that program participation levels have been relatively stable and that the current Schedule 91 collection rate has resulted in a surplus balance of nearly $1.5 million in December 2013. Assuming the $1.60 monthly increase is applied to an average of 30,000 qualifying customers over 12 months, the increase in the LILC is an additional $594,000 per year. Given that a $1.5 million surplus in the account is available for distribution, the current level of the

Schedule 91 rates appears to be adequate for funding the Low Income Lifeline Program.

Q: WHAT IS THE OFFICE'S RECOMMENDATION ON THE COMPANY'S PROPOSAL TO INCREASE THE RESIDENTIAL LILC CREDIT?

A: The Commission should approve the Company's proposed $1.60 per month increase in the LILC. Residential rates have continued to steadily rise since 2009 and the proposed $1.60 increase in the LILC can be implemented without increasing the Schedule 91 collection rate. Further, the Company should continue to monitor the LILC balance and provide information, including any recommended changes, as part of its annual report. The Division, Office and other interested parties can respond to any proposed changes to the LILC at that time.

Utah Marginal Cost Study

Q. WHEN DID THE COMPANY LAST PREPARE AND FILE A MARGINAL COST STUDY FOR UTAH?

A. The Company filed a new Utah Marginal Cost Study in Docket 10-035-124. It represented a comprehensive study and has not been updated since early 2011. Since that time, the Company's load forecasts have decreased, the costs associated with certain resources have declined and gas and wind resources have been pushed out in the planning horizon. The confluence of these factors has likely reduced long run marginal costs.

Q. IS THE COMPANY REQUIRED TO REGULARLY FILE MARGINAL COST STUDIES IN OTHER STATES TO SUPPORT ITS RATE DESIGN PROPOSALS?

A. The Office understands that the Company regularly prepares and files marginal costs studies in California and Oregon as part of rate proceedings.

Q. WHY IS IT IMPORTANT TO HAVE RECENT ESTIMATES OF THE LONG RUN MARGINAL COST FOR VARIOUS COST CATEGORIES?

A. If the analysis and information underlying a marginal cost study is determined to be reasonably accurate, the Company's estimate of the long run marginal cost for demand and energy can be used to design rates for customer classes. For example, the Office has been especially concerned about sending proper price signals to residential customers relating to the incremental cost of generation and transmission resources. Specifically, we have relied on marginal cost information in recent GRCs to set the residential summer tail-block rate so it reasonably tracks the long run marginal cost of demand and energy.

Q. WHAT IS THE OFFICE'S RECOMMENDATION??

A. The Commission should require the Company to completely update the Utah marginal cost study every three years. In addition, the Company's current estimates of the long run marginal cost for generation and transmission by class, including all supporting spreadsheets and data, should be provided as a normal filing requirement in future Utah GRCs.

Residential Net Metering Facilities Charge

Company Net Metering Proposal

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL REGARDING A NEW RESIDENTIAL NET METERING FACILITIES CHARGE.

A. The Company proposes to apply a new net metering (NM) facilities charge of $4.25 per month to residential customers participating in the net metering program (Schedule 135). The Company proposes that the $4.25 charge be uniformly applied to residential NM customers, irrespective of a NM customer's output to the grid. Two primary reasons are offered by RMP in support of the new NM facilities charge. First, the Company claims that the output from NM customers has an increased impact on the Company's local distribution system. Specifically, the Company alleges that it has had to frequently modify the distribution network to mitigate negative impacts on the grid and the NM output has increased wear on equipment. (Steward Direct, 520-526) Second, the Company states that crediting of the full retail energy rate to NM customers results in these customers not covering a fair share of fixed costs that are incurred to serve them and shifts fixed costs to other customers. (Steward Direct, 504-515)

<u>Impacts on Distribution System</u>

Q. DID THE COMPANY OFFER ANY EVIDENCE IN ITS DIRECT TESTIMONY SUPPORTING ITS CLAIM THAT IT HAS HAD TO FREQUENTLY MODIFY ITS DISTRIBUTION SYSTEM TO ACCOMMODATE NM OUTPUT AND THAT THIS OUTPUT HAS INCREASED WEAR ON EQUIPMENT?

A. No. The Company provided no evidence in its direct testimony detailing any modifications to its distribution system or increased wear and tear on equipment resulting from residential NM output. When asked in discovery for evidence relating to (i) modifications to the distribution grid precipitated by these 2,139 NM residential customers, (ii) negative impacts on the grid that were mitigated via modifications to the grid and (iii) the total cost of these modifications, the Company responded:

“The Company does not have a repository where system upgrades and the corresponding costs for each individual net metering project are collected.” (Response to OCS DR 15.14)

Thus, the Company was unable to provide any credible evidence either in direct testimony or in response to OCS discovery that output from Utah residential NM customers was materially impacting its Utah distribution system.

Q. DID THE OFFICE REQUEST ANY AVAILABLE STUDIES OR INFORMATION SO THAT IT COULD BETTER UNDERSTAND POSSIBLE IMPACTS OF RESIDENTIAL NM ON A UTILITY’S DISTRIBUTION SYSTEM?

A. The Office requested information along these lines in OCS DR 15.15(d). In response, the Company cited to two publications:

- Barker, P.P.; De Mello, R.W., "Determining the impact of distributed generation on power systems. I. Radial distribution systems," *Power Engineering Society Summer Meeting, 2000, IEEE,* vol 3, pgs. 1645-1656.
- "Improving economics of solar power through analysis, forecasting, and dynamic system modeling;" submitted by EnerNex to the Regents of the University of California, San Diego, October 2013.

The "Barker and De Mello" paper was provided by the Company and designated as confidential. This paper has been already provided to parties in the GRC that have signed the confidentiality agreement and is separately provided to the Commission at this time. The "EnerNex" report is available on the internet.

Q. PLEASE COMMENT ON THE ISSUES ADDRESSED IN THE BARKER AND DE MELLO PAPER.

A. Barker and De Mello raise the possibility that a small residential PV system could result in voltage control concerns depending on where the PV customers are located along the feeder system. The authors also discuss issues relating to harmonics (short circuiting or "flicker") and islanding (a generator continuing to operate when a power line malfunctions). However, the authors do not believe that a small residential PV system would contribute much to flicker or islanding.

Q. PLEASE COMMENT ON THE ISSUES ADDRESSED IN THE "ENEREX" REPORT.

A. The Enerex Report contains a scenario analysis describing the impact of different PV penetration levels (low versus high) on "tap changer" operations[11] under varying weather conditions (cloudy to overcast day; clear day). The Enerex Report indicates that during clear days tap changer operations are not affected

[11]Tap changers on distribution transformers regulate or adjust voltage levels.

very much by any level of PV. Even on cloudy days, the low PV penetration scenario (2.5%) does not significantly impact tap changer operations. These scenarios are set forth on Page 15 of the Report.

Q. IN ITS DIRECT TESTIMONY, DID THE COMPANY PROVIDE ANY EVIDENCE RELATING TO THE ISSUES DISCUSSED IN THE BARKER AND DE MELLO PAPER OR ENEREX REPORT?

A. No. While the Barker and De Mello paper suggests that the location of residential NM customers along a feeder line could pose voltage control concerns, the Company has not provided any evidence that this situation has occurred on its Utah distribution system or is expected to take place as the residential NM program expands. Further, the Company has not provided any evidence that the presence of the residential NM load has impacted tap changer operations.

<u>Residential NM Program Costs and Benefits</u>

Q. ARE THERE ANY RECENT CHANGES IN UTAH LAW IMPACTING THE ANALYSIS OF THE NM PROGRAM?

A. Yes. The 2014 Utah legislature passed second substitute SB 208, which addressed net metering and became effective May 13, 2014. The new statutory language requires the governing authority (the Commission in this instance) to:

"Determine, after appropriate notice and opportunity for public comment, whether costs that the electrical corporation or other customers will incur from a net metering program will exceed the benefits of the net metering program, or whether the benefits of the net metering program will exceed the costs."

Q. DID THE COMPANY INCLUDE A COMPLETE SET OF COSTS AND BENEFITS IN ITS DIRECT TESTIMONY?

A. No. The Company's testimony was filed prior to the 2014 legislative session when this new statutory requirement was considered and passed into law.

Further, the Company's proposed NM facilities charge is limited to recovering only the distribution costs associated with serving the average Utah residential customer.

Q. DID THE OFFICE ASK THE COMPANY TO PROVIDE THE TOTAL COSTS ASSOCIATED WITH SERVING A RESIDENTIAL NM CUSTOMER?

A. Yes. This specific cost information was provided by the Company in response to OCS DR 28.2. The response divides total costs into fixed and variable categories and functionally separates these costs into generation, transmission, distribution, etc. components. Table 8 below replicates the cost information provided by the Company in this data response.

Table 8

	Total Cost[1]	Cost By Fixed and Variable		Cost By Function				
	(700 kWh/Mth)	Fixed[2]	Variable	Generation	Transmission	Distribution	Retail	Misc.
COS %	100%	69%	31%	55%	14%	26%	4%	1%
Present	$72.39	$49.95	$22.44	$39.82	$10.13	$18.82	$2.90	$0.72
Proposed	$76.08	$52.50	$23.58	$41.85	$10.65	$19.78	$3.04	$0.76

[1] Including base rate only, excluding all tariff riders and adjustment schedules.
[2] Including demand related G&T costs, distribution and retail fixed costs.

Q. DID THE OFFICE ASK THE COMPANY TO PROVIDE AN ESTIMATE OF BENEFITS FROM THE RESIDENTIAL NM PROGRAM?

A. Yes. In OCS DR 30.2, the Office requested detailed data on the energy and capacity (if applicable) avoided by residential NM output on an annual total dollar and $/kWh basis. In particular, we were seeking to better understand the types of energy and capacity resources (market purchases, peaking resources, etc.) avoided by NM production over different time periods. However, the Company was unable to provide any analysis of benefits stating:

> "The Company does not measure the output of the customer-owned distribution generation facilities." (Response to OCS 30.2)

The Office found this response somewhat perplexing because the Company surely has the capability to at least estimate the aggregate output profile of residential NM and determining the resources that NM production would offset over different time periods.

Q. WHAT IS THE OFFICE'S PERSPECTIVE ON THE INFORMATION PROVIDED BY THE COMPANY?

A. At this point, the Commission would need a more complete set of information to accurately determine the value of NM output and compare it to the total costs of serving a residential NM customer. We expect that the benefits derived from NM production would offset a portion of the fixed and variable costs in the generation and transmission categories. However, the Office does not believe that evidence can be produced to show that the residential NM output provides enough value to offset distribution costs. The Office notes that NM customers use the distribution system both to serve their load when their PV systems are not producing *and* to put excess generation onto the power grid. Therefore, as discussed in the next section of my direct testimony, the Office is concerned about the shift in distribution-related fixed costs from NM to non-NM residential customers.

Fixed Cost Recovery

Q. WHAT ADDITIONAL SUPPORT DOES THE COMPANY PROVIDE FOR ITS PROPOSED RESIDENTIAL NM FACILITIES CHARGE?

A. By compensating residential NM customers with the full value of the retail energy rate, the Company asserts that NM customers do not cover enough of distribution-related fixed costs and results in costs shifted to other customers. (Steward Direct, lines 496-498).

Q. DOES THE OFFICE AGREE WITH THE COMPANY ON THE NEED TO DEVELOP AND IMPLEMENT A FACILITIES CHARGE FOR NM CUSTOMERS?

A. Yes. The Office supports the concept of assessing a new NM facilities charge on the bills of residential NM customers. If a NM facilities charge is not developed to recover distribution-related fixed costs, there will continue to be a cost shift from residential NM customers to non-NM residential customers.

Q. HAS THE COMPANY PROVIDED A CURRENT ESTIMATE OF THE LEVEL OF COSTS SHIFTED TO NON-NM RESIDENTIAL CUSTOMERS?

A. In response to OCS DR 30.1, the Company provided cost shift estimates that vary by the assumption used for solar PV capacity factors. Assuming a 20% capacity factor for residential solar PV systems, the annual cost shift estimate is currently at $701,000.[12] However, the cost shift will increase as more and more residential customers elect to install solar PV systems. If the current growth rate of 30% continues, then the residential NM load can be anticipated to double in about three years time. This means the cost shift could approach $1.5 million in just a few years.

<u>NM Charge – Flat vs. kW Output</u>

Q. DOES THE OFFICE AGREE WITH THE COMPANY'S PROPOSED METHOD USED FOR CALCULATING THE NEW FACILITIES CHARGE?

A. The Office generally supports the method used by the Company to calculate the new facilities charge. However, we recommend against imposing a uniform (flat) monthly charge on all NM customers, irrespective of a NM customer's PV output. Instead, the Office proposes to implement the charge on a $/kW basis so that the monthly amount paid by individual NM customers would reflect the rated production capability of each PV system.

Q. PLEASE EXPLAIN WHY THE OFFICE PROPOSES THAT THE COMMISSION ADOPT A PER/KW NM CHARGE INSTEAD OF A FLAT FEE.

A. The Barker and De Mello paper discussed earlier suggests that smaller residential PV systems may be easier to plan for and integrate into a utility's

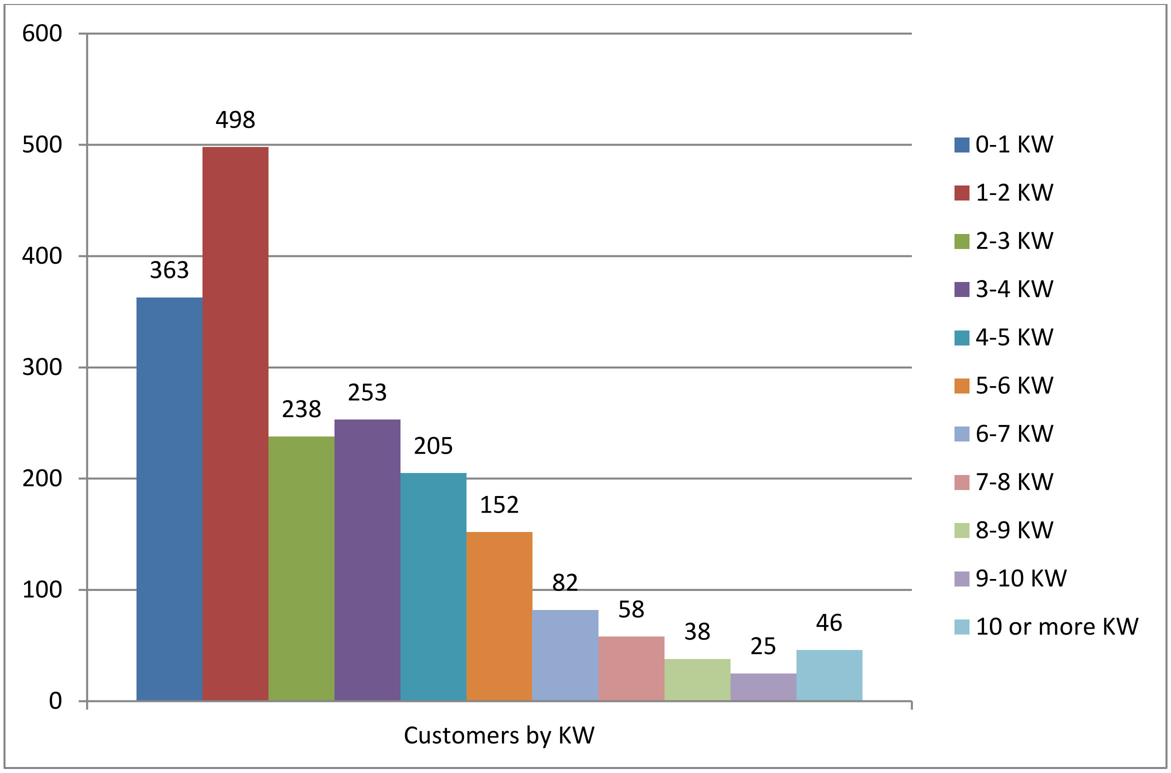
[12] The literature on residential solar PV systems suggests that PV capacity factors range between about 18-25% across regions. EIA's most recent solar PV capacity estimate is 25% (EIA's Energy Outlook, released May 7, 2014). The Office relied on a slightly lower figure of 20% to be conservative.

network than larger PV systems. More importantly, it seems only fair that a smaller 2 kW NM customer should have to contribute less revenue to cover fixed costs than a larger 10 kW NM customer. A method that recovers revenue from NM customers based on the rated production capability of individual PV systems better reflects cost causation and fairness versus the flat NM facilities charge proposed by the Company.

Q. DO YOU HAVE A TABLE THAT PROVIDES A RECENT DISTRIBUTION PROFILE FOR RESIDENTIAL PV SYSTEMS IN UTAH?

A. Table 9 below indicates the distribution of installed residential PV systems as of February 2014. As shown in Table 9, the distribution is skewed such that slightly more than 50% of residential PV systems are rated at less than 3 kW. Therefore, more than half of PV systems in Utah are relatively small in size and under the Office’s proposal these smaller residential NM customers would have to contribute less to fixed cost coverage compared to NM customers with larger PV systems.

Table 9



Q. HAS A SIMILAR NM FACILITIES CHARGE TIED TO KW PRODUCTION OF PV SYSTEMS BEEN APPROVED BY ANY OTHER STATE COMMISSION?

A. Yes. On December 3, 2013, the Arizona Corporation Commission (ACC) published an order approving a compromise between the Residential Utility Consumer Office (RUCO) and parties representing solar interests that established an interim monthly charge of $0.70/kW to be applied on the bills of future solar customers of Arizona Public Service (APS), effective January 1, 2014.[13] The new NM charge will collect approximately $4.90/month based on the estimated average size (7 kW) of residential PV systems. The NM charge is expected to be revisited in APS's next GRC.

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[13]In its December 2013 Order in Docket E-01345A-13-0248 (Decision 74202), the ACC entered a finding, based on the evidence presented by the Arizona Staff and RUCO, that a $3.00/kW NM charge is reasonable for new solar NM customers. This $3.00/kW NM charge translates to a $21.00/kW charge for the average (7 kW) residential NM customer in APS's service territory. While the ACC approved an interim NM charge of $0.70/kW until APS's next GRC, it nevertheless made a specific finding that $3.00/kW represented a cost-based NM charge (see Decision 74202, pg. 23, paragraph 84).

Office NM Proposal

Q. PLEASE DESCRIBE THE OFFICE'S PROPOSAL FOR A RESIDENTIAL NM CHARGE.

A. As shown in my Exhibit OCS 5.2, the Office has calculated a "flat" NM charge of $4.82 month. On a $/kW basis, the $4.82 charge would amount to $1.60/kW. Under the Office's proposal a residential customer with a 1 kW solar PV system would pay a NM facilities charge of $1.60/month and a residential customer with a10 kW solar PV system would pay a charge of $16.00/month.

Q. WHILE THE OFFICE IS NOT RECOMMENDING A FLAT NM FACILITIES CHARGE, WHY IS THE OFFICE'S CALCULATED FLAT CHARGE HIGHER THAN THE COMPANY'S PROPOSED $4.25/MONTH FLAT CHARGE?

A. The NM facilities charge is inversely related to the level of the residential customer charge as the Company's proposal uses both rate design elements to collect some of the fixed costs associated with the distribution system. The higher the customer charge level the lower the calculated NM facilities charge. Since the Office's proposed customer charge is $2.00 less per month than the Company's $8.00 recommendation, less fixed costs are recovered through the customer charge and more will be recovered by the NM facilities charge.

NM Facilities Charge – Policy Issues

Q. ARE THERE STRONG PUBLIC POLICY REASONS FOR IMPLEMENTING A NM FACILITIES CHARGE IN THIS GRC?

A. Yes. The Office considers it important for the Commission to send a clear policy signal in this proceeding on the NM facilities charge so that potential NM customers can make an informed economic decision when evaluating whether or not to invest in a solar PV system. Delaying a decision on the NM facilities charge would create uncertainty for prospective NM customers while leaving the current cost shift issue unresolved. Therefore, the Commission needs to develop a blueprint for its NM policy because postponing a decision on the facilities charge issue is both unfair to future NM and non-NM residential customers.

Q. THE COMPANY'S PROPOSAL APPLIES THE NEW NM CHARGE TO BOTH CURRENT AND FUTURE RESIDENTIAL NM CUSTOMERS. WHAT IS THE OFFICE'S POSITION ON THIS ISSUE?

A. The Office would prefer establishing a policy that any new residential NM charge approved by the Commission be applied only to the utility bills of <u>future</u> NM residential customers after September 1, 2014. Under this policy structure, the existing 2,137 residential NM customers would be grandfathered and not be assessed the NM facilities charge. This policy is consistent with the interim approach taken by the ACC in its recent NM Order for APS and a recent decision by the California Public Utilities Commission. Such a policy avoids immediate rate impacts for existing residential NM customers.

Q. HAS THE OFFICE INVESTIGATED WHETHER SUCH A NM POLICY COMPORTS WITH THE UTILITY STATUTES AND LAWS THAT THE COMMISSION OPERATES UNDER IN UTAH?

A. The Office's view is that selective application of the new NM facilities charge to only future NM customers could be problematic given Utah's utility statutes. If the Commission would like to explore the possibility of grandfathering existing NM customers, it should require that legal issues involving the application of any approved NM facilities charge to only future residential NM customers be addressed by party attorneys in case briefs.

Q. PLEASE EXPLAIN WHY IT IS NECESSARY TO ADDRESS THIS COST SHIFT IN THIS PROCEEDING?

A. Although it may not be possible to grandfather existing NM customers, it is important to minimize the number of customers that are impacted by a change in NM policy. Further, it would be contrary to cost causation principles for the Commission to allow the current situation to continue, given that the cost shift from NM customers to non-NM metering customers is anticipated to grow and eventually become material and potentially large.

Q. DOES THE OFFICE HAVE ADDITIONAL RECOMMENDATIONS?

A. Yes. The Office recommends that the Company develop stronger messaging to provide to current and potential future residential NM customers. This messaging should clearly outline the Commission's NM policy and the specific manner in which rates for NM customers are anticipated to change over time. This would allow the Company and affected parties to communicate reliable information to potential residential NM customers so they can make an informed decision on whether or not to participate in the NM Program.

Q. HOW SHOULD THIS NM MESSAGING BE DEVELOPED AND IMPLEMENTED?

A. At the conclusion of this GRC, the Office recommends that the Commission require interested parties to meet and develop appropriate messaging that reflects the Commission's order and policy direction on the NM issue. The results of such an effort should be presented to the Commission as part of a compliance filing. The Office recognizes the Commission may have some reluctance to involve itself in the day-to-day operations of the utility. However, the Office believes that in this instance the public interest can only be served by the Commission overseeing this important piece of communication between the Company and its residential customers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.