BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN UTAH AND FOR APPROVAL OF ITS PROPOSED ELECTRIC SERVICE SCHEDULES AND ELECTRIC SERVICE REGULATIONS	)))))))))	**DOCKET NO. 13-035-184** **DPU Exhibit 11.0 DIR-COS**

COST OF SERVICE

(RATE DESIGN)

DIRECT TESTIMONY OF STAN FARYNIARZ

ON BEHALF OF

THE UTAH DIVISION OF PUBLIC UTILITIES

May 22, 2014

I. INTRODUCTION

Q. What is your name and business address?

A. My name is Stan Faryniarz. I work for La Capra Associates, headquartered at One Washington Mall, Boston, MA 02108.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Utah Division of Public Utilities ("Division" or "DPU").

Q. Please describe your background and experience.

A. I am a Managing Consultant at La Capra Associates. I have been with this energy planning and regulatory economics firm for 15 years. I have prepared testimony on water and electric rates, phase in mechanisms, cost allocation and other issues for, or associated with, a number of utilities in the states of Maine, New Hampshire, Vermont, Rhode Island and Pennsylvania. I have provided expert testimony on these and other subjects in all of the above states except New Hampshire, and on other subjects in the state of Maryland and in Nova Scotia, Canada. Prior to my employment at La Capra Associates, I was a consultant for two different consulting firms in Maine and Vermont. I began my career as a regulatory professional with the Vermont Department of Public Service. My resume is attached as DPU Exhibit 11.1 DIR-COS.

Q. Please describe your educational background.

A. I have a bachelor's degree with honors in Economics, and a Masters in Public Administration (finance and managerial economics concentration) from the University of Vermont. I have completed additional post-graduate coursework in Regulatory Economics, and I hold the Certified Energy Procurement (CEP) Professional credential from the Association of Energy Engineers.

Q. What is the purpose of your testimony?

A. I have been retained by the Division to review and analyze the rate design presented by Rocky Mountain Power ("RMP" or "the Company"). I determined a rate spread and rate designs based on the cost allocation studies presented by Division witness Ms. Lee Smith, including one study which reflects the Division's revenue requirements as a basis for determining class revenue requirements. The Division's rate objectives and class revenue requirements provide the basis for rate design recommendations, which I will also present and which will also be discussed by Division witness Dr. Artie Powell.

Q. What material did you review before you prepared your testimony?

A. My point of departure was the analysis of the Company's rate design proposal, as outlined in testimony provided by the RMP's Director of Pricing, Cost of Service, and Regulatory Operations, Joelle R. Steward. I also reviewed various data requests and responses in this docket. I have also reviewed certain materials associated with other

Public Service Commission of Utah ("Commission") proceedings that are relevant to this one.

Q. What areas will your testimony address?

A. I will address the following:

- The Company's failure to prepare or base its rate design proposal upon a recent marginal cost study of the cost to serve its Utah customers.
- The appropriateness of the Company's proposed residential customer charge.
- The appropriateness of the Company's proposed net metering charge and related public policy issues.
- The Company's proposal to move rates only partially toward allocated cost of service ("COS").
- An alternative rate spread proposal that moves customer classes towards allocated COS and is based upon the DPU Staff's recommended revenue requirement and allocated COS study.
- An error in Schedule 15 revenues.
- Other miscellaneous issues.

Q. Please summarize your conclusions.

A. My conclusions are as follows.

- The Company has not attempted to base its time of use energy rates or other rate components on marginal costs and therefore at least three of its stated rate objectives may not be satisfied, including rates that reflect cost causation, and which lead to equity and economic efficiency.

- The amount of the Company's proposed increase in the residential customer charge is not warranted and the residential customer charge should instead remain at the current $5 per month level, assuming the Commission accepts the Division's recommended revenue requirement or something relatively close.
- The Net Metering Charge should be reviewed carefully within the context of a benefit-cost analysis, to the extent practicable, in this rate proceeding, as directed in recent Utah legislation, Senate Bill 208. The Company has not provided such a benefit-cost analysis of the net metering program. As discussed by Division witness Dr. Artie Powell, the Division has reviewed the Net Metering Charge proposed by the Company and finds that it is within the zone of reasonableness and that it acceptably balances costs and benefit until such a study can be undertaken.
- The customer class revenue requirements and rates should be based more directly on the results of an appropriate allocated COS study. This will result in greater movement of class revenue requirements from current levels than the Company proposes, and correspondingly different bill impacts, but will further achieve the Company's stated objectives of cost-based rates, equity and economic efficiency.

II. MARGINAL COST AND RATE DESIGN

Q. Did the Company include a marginal cost study in its application?

A. No.

Q. Has the Company ever included a marginal cost study in a recent rate case application?

A. Yes. As a result of the Commission-approved settlement in Docket No. 09-035-23, the Company included a marginal cost study in its application in Docket No. 10-035-124.

Q. Was that marginal cost study Utah-specific?

A. No, it was an Oregon-specific study.

Q. Would including a marginal cost study be useful to the rate design process? If so, would a Utah specific marginal cost study be best?

A. The answer to both questions is yes.

Q. How would a marginal cost study be useful to the rate design process?

A. Basic economic principles suggest that utility customers can make optimal decisions regarding consumption only when prices inform them of the cost of their decision on whether to consume more or less energy. This concept is complicated by differences between long-run and short-run marginal costs, and the recognition that costs which are external to the utility (i.e. societal costs) are not reflected in the utility's marginal cost.

One primary reason for a marginal cost study to guide development of rates is that an energy charge should inform customers of how much additional cost is incurred in the short run when customers use additional energy, and a capacity charge should inform customers of how much it will cost to add generation, transmission and distribution capacity if peak load increases.

Q. Why would a Utah specific marginal cost study be best?

A. It would reflect marginal distribution costs and other marginal costs jurisdictional to Utah.

As the Company points out in response to DPU data request 25.1, "[i]n the 2011 Utah General Rate Case, the last year that the Company filed a marginal study, the unit costs in the filed marginal cost study were very different than the results of the Oregon studies filed in 2010 and 2012 (a rate case was not filed the same year as Utah)." It is reasonable to expect that would be the case for an updated study of Utah-specific marginal costs.

Given how the RMP system is dispatched, Utah generation and transmission costs are likely to reflect those associated with the broader PacifiCorp western control area. But distribution system costs are not the same across different jurisdictions. For instance, the recent Oregon marginal cost study reflected only Oregon-specific distribution costs (see Company response to DPU data request 38.1).

Q. Was it problematic that the Company did not file a Utah-specific marginal cost study in this rate case application? Why?

A. Yes. As Company witness Ms. Steward notes, "[t]he Company's objectives in this case are to implement the proposed rate increase while reflecting cost causation, equity, economic efficiency, revenue adequacy, and minimizing customer impacts." (Steward Direct Testimony, p. 2)

Unless a study of the marginal costs of providing service is conducted to guide the development of rates, the first three objectives may not be satisfactorily achieved. As discussed further in my testimony, the Company proposes to raise customer charges in a number of classes including residential, but then to maintain or "bake in" the other current rate structures including energy rates and, where applicable, demand charges, by proportional adjustment. Without a Utah-specific study of the short-term and long-term marginal costs of service, there is no way to tell whether the current rate design results in customers paying too much or too little for the costs of their consumption, whether there exist any cross-subsidies benefitting some customers at the expense of others, or whether price signals are leading to economically optimal consumption decisions that effectuate least-costs for both the customer and the utility in the long run.

Q. What justification did the Company provide for retaining the current rate structure relationships?

A. The Company maintains in response to DPU data request 17.29, that "[t]he [COS] results did not indicate that changes were needed in the relationship among all the rate components including customer, facilities, demand and energy charges; therefore, the Company proposed to increase the rates of all rate components uniformly for most rate schedules."

However, the COS study focused on embedded, not marginal costs, so there remains some question about whether *embedded* cost rates send proper rate signals about *marginal* costs going forward. A Utah-specific marginal cost study could be helpful in deciding whether a more significant restructuring of the non-customer charge rates is in order.

The rest of the response to the same data request suggests a more direct reason for the Company's decision to maintain current rate relationships. It states that its proposed rate design "also ensured that the impact of the price change would be fairly uniform across different load sizes and load factors for these rate schedules." I will discuss this objective of constraining revenue requirement shifts and bill impacts later in the next section.

Q. What do you suggest the Company be required to do in the future with respect to reviewing its marginal costs of serving Utah customers?

A. I suggest the Commission direct the Company to file an appropriate study with its next general rate case and rate design filing to guide the development of all rate components in order to ensure that rates reflect the principles of cost causation, equity, and economic efficiency.

III. RATE DESIGN ISSUES

Q. Have you found any problems with the Company's proposed rate design?

A. Yes. Fundamentally, the Company does not seem to have attempted to design rates to send better price signals or to improve the efficiency of use. The Company's major approach to rate design appears to be to produce relatively even and constrained bill impacts across different customer classes while increasing fixed cost recovery through a higher customer charge. While bill impacts are an important consideration, when the basic rate design has not been examined or justified in many years, the Company's approach may actually be moving rates further from appropriate price signals. The failure to examine the rate structure may also result in creating or increasing cross subsidies between classes and customers within a class. That would be economically inefficient and could lead to higher-than-necessary costs for both the customers and RMP.

<u>A. Residential Customer Charge</u>

Q. Is the Company proposing an increase to customer charges?

A. Yes. RMP proposes to increase the customer charge for a number of rate classes. While the focus herein is on the residential customer charge because of the size of the class and the amount of revenue generated from this charge relative to total residential revenues, some of the discussion and findings below are applicable as well to other classes.

Q. What has the Company proposed regarding the residential customer charge?

A. RMP proposes to increase the customer charge for virtually all rate classes. The Company has proposed to increase the residential customer charge from the current $5.00 per month to $8.00 per month, an increase of 60%. This charge is much higher than the customer charge that results from the 1985 methodology approved by the Commission. I believe the proposed increase is inconsistent with either the approved methodology or the method as modified in the settlement of Questar's last general rate case, Docket No. 13-057-05, and would lead to an inappropriate rate design.

Q. Please describe the 1985 methodology.

A. The currently-approved Commission methodology is designed to charge customers only for costs directly related to the number of customers. It includes only the return on and depreciation expense associated with meters and service drop plant, the expense of reading meters (Account 902.1) and also billing expense (Account 903.2). Without making any other adjustments to the Company-requested revenue requirements or the allocated COS study, this would result in an average customer cost of $3.80 per month, $1.20 less than the current customer charge. The table below presents the workup of this number, based on the Company's response to Office of Consumer Services data request 5.8 (a).

Q. What would the customer charge be if it were based upon the 1985 Commission-approved methodology?

A. Table 1 below sets forth the result of applying the 1985 Commission-approved methodology to the filing in this case.

Table 1 – RMP Calculation of Customer Charge Based on 1985 Commission-Approved Methodology

	Description	a. 1985 Methodology
1	Customer Billing & Accounting Expense (acct. 903.2)	$0.49
2	Meter Reading (acct. 902)	$0.48
3	Meters - Depreciation Expense	$0.20
4	Meter Plant (acct. 370)*	$0.66
5	Meters - Accumulated Depreciation*	-$0.23
6	Service Drop - Depreciation Expense	$0.45
7	Service Drop Plant (acct. 369)*	$2.42
8	Service Drop - Accumulated Depreciation*	-$0.67
9	Total Customer Charge	$3.80

Q. Since the customer charge in this case is not consistent with the 1985 methodology, does the Company justify its proposed customer charge increase here?

A. Ms. Steward argues against the approved methodology and for a much more expansive, alternative definition of customer costs. She argues that it is appropriate to charge customers monthly for the "fixed costs" of serving residential customers. The other description she uses for the alternative portrayal of customer costs is "costs that do not vary with usage" (Steward Direct Testimony, p. 13). She includes all fixed costs allocated to the distribution and retail functions. Using this characterization of costs, Ms. Steward computes a residential monthly customer cost of $24.72. She does not propose to set the customer charge at this level at this time, but she refers to the fixed cost accounting as justification for the proposed increase in the customer charge.

Q. Do you think that the distribution "fixed costs" are actually fixed and should be charged to every residential customer?

A. No. These "fixed costs" include all distribution costs, all retail costs, and an allocation of joint costs. While the cost of the distribution system is fixed in the short run, the overall embedded cost of the distribution system has been determined by the number of customers it serves, the demands of those customers, including individually, by class, and in total, and by when the various components were built. However, these costs are not immutable, and to charge customers as if they were does not provide a proper price signal. With regard to what the Company labels "retail costs", while it might be argued that some of these costs are considered directly customer-related, the Company has not provided sufficient evidence that these should all be included in customer costs.

Q. What "retail costs" are appropriate to include in the customer charge?

A. The cost causation principle of ratemaking suggests that costs should be considered as customer costs only when the major cost driver is in fact the number of customers – i.e. as customers are added, the costs increase. The only "retail costs" that should be included in the customer charge were those that were included in the 1985 methodology, namely customer accounting and billing (Account 903.2), and customer metering (Account 902.1) costs.

Q. What are the impacts of this move toward defining customer costs as fixed costs?

A. Since the foundation for its proposed $8 customer charge is this “fixed costs” accounting, what it labels as customer costs, the Company is clearly trying to collect more of its revenues from the fixed monthly customer charge. One apparently desirable impact from the Company’s perspective is that its revenue stream will become less variable, since less revenue will be collected from energy (and where appropriate demand) rates that depend on consumption. For the residential class, as the customer charge goes up, energy charges will need to decrease to remain revenue neutral.

Notably, the Company is very concerned that energy use is decreasing. But it is unclear why it thinks this rate design change is reasonable or will assist it in retaining energy sales. On the one hand, Ms. Steward asserts that “[i]n today’s environment … we encourage reductions in usage where possible and attempt to achieve efficient usage in all circumstances.” (Steward Direct Testimony, p. 14) But then she argues that her proposed rate change will not have a dampening effect on conservation, referring only to the proposed $8 customer charge and not to the almost $25 charge that she theoretically supports. (Steward Direct Testimony, p. 15)

Q. Do you believe that the 1985 Methodology includes all customer-related costs?

A. No. If the appropriate definition of customer costs is all costs and expenses that are primarily driven by the number of customers, then the previously approved methodology does not include all costs associated with meters and service drops. If these plant items are clearly and directly related to the numbers of customers, all costs associated with them are also customer-related. It would be inconsistent to allow the costs associated with financing these plant items, but not the maintenance costs necessary to keep them operating.

Q. Do you believe any changes to the 1985 Methodology are justified?

A. Yes. I believe that it is appropriate to add in to the current definition all costs associated with services and meters. I will call this the Division 2012 Methodology, as it is similar to the method used in reaching a settlement in 2012 for Questar Gas, in Docket No. 13-057-05 Questar Gas Company General Rate Case, which was approved by the Commission. I have therefore added to the 1985 amounts, expenses associated with services.

Unfortunately, there is no separate account for service expense, which is included with overhead line expenses. Therefore, I have split these expenses proportionally based on the relationship between service plant and overhead conductors.

Using the RMP-requested revenue requirement and its allocated COS study results, the customer charge would be $5.34 per month. This calculation is shown in the table below.

Table 2 - Division 2012 Methodology Customer Charge Calculation Based on RMP - Proposed Revenue Requirement and Allocated COS Study

		Division 2012 Methodology			
	Description	1. Rate Case Cost Components	2. Return on Rate Base	3. Total Revenue Requirements	4. Rev. Req. / Number of Customers / 12
1	Customer Billing & Accounting Expense (acct. 903.2)	$4,358,176		$4,358,176	$0.49
2	Meter Reading (acct. 902)	$4,246,884		$4,246,884	$0.48
3	Meters - Depreciation Expense	$1,789,685		$1,789,685	$0.20
4	Meter Plant (acct. 370)*	$53,461,906	$5,821,646	$5,821,646	$0.66
5	Meters - Accumulated Depreciation*	-$18,766,774	-$2,043,577	-$2,043,577	-$0.23
6	Service Drop - Depreciation Expense	$3,957,167		$3,957,167	$0.45
7	Service Drop Plant (acct. 369)*	$197,825,000	$21,541,827	$21,541,827	$2.42
8	Service Drop - Accumulated Depreciation*	-$54,565,848	-$5,941,858	-$5,941,858	-$0.67
9	Meter plant expense (acct 586)	$1,413,900		$1,413,900	$0.16
10	Service Plant Expense	$12,350,490		$12,350,490	$1.39
11	Average Customers	740,636		740,636	
					$5.34

* Assumes 10.89% Weighted Before-Tax Capital Cost

Q. Is this your recommended customer charge?

A. No. These calculations do not reflect the DPU-recommended revenue requirement or allocated COS study. Using the Division 2012 Methodology with adjustments reflecting the DPU-recommended revenue requirement[1] and allocated COS study,[2] the calculated customer charge is $5.18 per month. This calculation is shown in the table below.

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[1] See the testimony of DPU Staff witness Mr. Mathew Croft.
[2] See the testimony of DPU Staff witness Lee Smith.

Table 3 - Division 2012 Methodology Customer Charge Calculation Based on DPU Staff-Proposed Revenue Requirement and Allocated COS Study

		Division 2012 Methodology			
		1.	2.	3.	4.
	Description	Rate Case Cost Components	Return on Rate Base	Total Revenue Requirements	Rev. Req. / Number of Customers / 12
1	Customer Billing & Accounting Expense (acct. 903.2)	$4,270,679		$4,270,679	$0.48
2	Meter Reading (acct. 902)	$4,237,414		$4,237,414	$0.48
3	Meters - Depreciation Expense	$1,789,137		$1,789,137	$0.20
4	Meter Plant (acct. 370)*	$53,436,820	$5,458,598	$5,458,598	$0.61
5	Meters - Accumulated Depreciation*	-$18,867,290	-$1,927,303	-$1,927,303	-$0.22
6	Service Drop - Depreciation Expense	$3,934,880		$3,934,880	$0.44
7	Service Drop Plant (acct. 369)*	$196,720,282	$20,095,074	$20,095,074	$2.26
8	Service Drop - Accumulated Depreciation*	-$54,700,554	-$5,587,689	-$5,587,689	-$0.63
9	Meter plant expense (acct 586)	$1,410,321		$1,410,321	$0.16
10	Service Plant Expense	$12,312,487		$12,312,487	$1.39
11	Average Customers	740,636		740,636	
	* Assumes 10.22% Weighted Before-Tax Capital Cost				$5.18

Because the resulting calculated customer charge is very close to the existing one, the DPU recommends rounding down and retaining the current customer charge of $5 per month. Of course, the final calculation will depend on the overall revenue requirement and return on equity approved by the Commission. If the case's outcome is much different from the Division's position, the Division recommends rounding the calculation to the nearest dollar or perhaps half-dollar.

B. Net Metering Charge & Policy

Q. Please describe the Company's proposal for a new net metering charge.

A. The Company is proposing to implement a new monthly facilities charge, Schedule 135, for residential net metering customers. This would be levied on top of the monthly customer charge. It is intended to collect fixed distribution and retail costs that are not collected when a customer's net metering production offsets enough usage to substantially reduce or eliminate energy charges which would otherwise recover those fixed costs. In addition, the Company maintains that there are other costs it incurs by virtue of the existence of the net metering facility, such as wear and tear on transformers because of bi-directional energy flows. The Company proposes under Schedule 135 that each net metering customer pay a net metering charge of $4.25 per month.[3]

Q. Do you agree conceptually with a net metering charge?

A. I generally agree with the concept of a net metering facility charge. One of the Division's guiding principles is that rates and charges should reflect cost causation and that cost responsibility should be borne by those causing the incurrence of such costs.[4]

Q. Please elaborate on cost causation and cost responsibility.

A. Under the cost causation principle of ratemaking, rates should recover all costs caused by customers' electricity consumption. When they do not, the resulting price signals can lead to inefficient consumption decisions and higher overall costs for the non-net metered customers and for the utility itself in the long run. If net metering facility production is enough to offset a customer's consumption, no energy charge revenue will be collected, including distribution system fixed cost recovery or recovery of other fixed costs built

[3] See, generally, Direct Testimony of Joelle R. Steward.
[4] See Dr. Artie Powell's Direct Testimony for a discussion of the Division's guiding principles. I am not the policy witness and discuss these principles in general only.

into volumetric rates. When that happens, there is an inherent cross-subsidy from non-net metered customers to those with net metering facilities.[5]

For these reasons, I generally support the concept of recovering net metering costs from net metering customers.

Q. Does the $4.25 net metering charge proposed by the Company fully recover all fixed costs?

A. No. The Company clearly points out that its net metering charge does not collect all fixed costs, but rather fixed distribution and retail costs only.[6]

Q. Did the Division do any calculations regarding a net metering charge?

A. Yes. Using data provided by the Company, and the Division's recommended customer charge of $5.00, the Division's calculated a net metering charge of $4.81. The table below represents the Division's calculations.

[5] For additional discussion of the economics associated with net metering and cost recovery, please review the testimony of Dr. Artie Powell on behalf of the Division.

[6] Direct Testimony of Joelle R. Steward, lines 527-534.

Table 4 – Calculation of Net Metering Charge Using RMP Model and DPU Staff-Recommended Customer Charge

Rocky Mountain Power - State of Utah
Calculation of Net Metering Facilities Charge With a $5 Per Month Customer Charge

		Residential	
Line	**Classified Rev Req**	**COS**	**Cost/ Customers**
1	Distribution - Substation	$34,377,992	$3.87
2	Distribution - Meter	$7,778,745	$0.88
3	Distribution - Service	$21,834,368	$2.46
4	Retail Total	$31,132,615	$3.50
5	Distribution - P&C	$82,641,933	$9.30
6	Distribution - Transformer	$33,743,506	$3.80
7	Total Distribution/Retail Costs	$211,509,159	$23.80
8	Proposed Customer Charge	$44,010,895	$5.00
9	Total Dist./Retail Fixed Cost not recovered in Customer Charge	$167,498,264	$18.80
10	Total kWh	6,203,851,850	
11	Net Metering kWh	13,012,995	
12	Total Bills	8,887,629	
13	Forecasted Net Metering Bills	25,117	
14	Average $/kWh for remaining Dist./Retail costs	0.026999	
15	Net Metering Dist/Retail Costs	$351,339	$13.99
16	**Net Metering Facilities Charge**		**$4.81**

Q. It appears that the Division's calculation results in a higher net metering charge than that proposed by the Company. Do you have any comments?

A. Yes. After looking at the results of the Division's calculation, I considered the ratemaking principle of gradualism when comparing the Company's proposed net metering charge to the charge calculated by the Division.

Q. In addition to it being one of the Division's guiding principles, is there any particular reason why you applied the principle of gradualism in this case?

A. Yes. The Company represents that there has been a rapid year-over-year growth of new net metering facility installations (almost 600 or 30% growth in new installations from 2012 to 2013 alone)[7] on the Company's system.

Q. Does applying the ratemaking principle of gradualism somewhat alleviate your concern about not achieving full cost recovery from net metering customers immediately?

A. Yes, it does. In this instance, because of the rapid increase in the number of net metering customers, moving from $0 cost recovery to less than full recovery is consistent with the Division's guiding principles. A net metering charge of $4.25 appears consistent with the principles of cost causation and cost responsibility, and gradualism. If upon a later review of the benefits and costs of net metering a different charge were found appropriate, it can be adjusted as necessary at that time.

Q. Do you have any comments regarding calculation and analysis of a net metering charge in future rate cases?

A. Yes. Recently, Utah Senate Bill 208, which addresses costs and benefits of net metering, among other issues, became effective. SB 208 was enacted by the Legislature and signed by the Governor after the filing of this rate case. I recommend that the Commission

[7] See Direct Testimony of Joelle R. Steward, lines 480-487.

open a docket to explore net metering costs and benefits and that the proceedings in that docket be considered by the Company if the Company files another rate case seeking approval of a net metering charge.

C. Rate Spread and Movement Towards Allocated Cost of Service

Q. Is the Company proposing to shift revenue requirements between customer classes to recover the costs it claims in its allocated COS study?

A. No. As discussed earlier in Section III of my testimony, the Company is proposing rate adjustments that move class revenues only partially toward its allocated COS study results.

Q. Why do you think the Company has not proposed to move all classes to their full cost?

A. The Company states that "[t]he proposed rate spread is designed to reflect COS results while balancing the impact of the rate change across customer classes." (Steward Direct Testimony, p. 10)

However, as discussed earlier in my testimony, it appears that the Company is primarily interested in evening out and constraining bill impacts to customer classes, while recovering more retail rate revenue from customer charges. Recognizing that, I do not believe the Company's rate design proposal goes far enough to reflect allocated costs of service.

Q. How has the Company proposed to spread its revenue requirement across rate classes?

A. The Company uses a rather complicated process to spread the revenue requirement across rate classes. I prepared DPU Exhibit 11.2 DIR-COS, [8] which shows the various steps required on page 1. These steps are summarized as follows:

1. The Company starts with the percentage change in revenues required to set each class equal to the COS, shown in Column C.
2. The Company then calculates the deviation of the percentage change in revenues from the targeted overall Utah RMP increase for each rate class. This is shown in Column D.
3. These deviations are multiplied by 0.25 to calculate the “D-Value” shown in Column G. There are some constraints on the D-Values:
    a. The schedule that is closest to COS, in this case Schedule 8, has a D-Value of zero and serves as a reference point for the other schedules.
    b. D-Values are capped so that the targeted rate increase of any schedule cannot be more than 8%.
    c. D-Values are rounded to the nearest percent.
4. The target increases for the classes are set equal to the D-Value plus the Middle Point. The Middle Point is adjusted until the overall target increase for Utah RMP is obtained.

[8] The exhibit does not show numbers that exactly match RMP’s requested increase because it does not include treatment of Annual Guarantee Revenues, but it is close enough to be illustrative for this purpose.

5. There are some exceptions to this method for some rate classes:
    a. Special Contract 1 is set to have a rate increase equal to the overall average for Utah.
    b. Special Contract 2 has no rate increase.
    c. Schedules with D-Values less than -3% have no rate increase.
    d. Schedules 21, 31, and Special Contract 3 have rate increases equal to the rate increase for Schedule 9.

Q. Has the Company ever moved rates to fully allocated COS?

A. RMP admits in response to DPU data request 17.20 that "[s]ince 2000, the Company has not proposed any rate spread to fully recover the revenue requirement based on the [COS] for each rate schedule."

Q. What issues do you have with the Company's proposed rate spread methodology?

A. My concerns are two-fold.

Most importantly, by dividing the deviations from allocated COS by 4, the rate classes only get one quarter of the way to COS from the Middle Point rate increase. If the Company were to always divide the deviations by 4 in successive rate cases, then no rate classes would ever have revenue requirements equal to their allocated COS. This would violate the cost causation and equity principles of ratemaking. While temporary adjustments to these principles are permissible to satisfy other ratemaking principles, enshrining a permanent failure to arrive at COS rates is not in the public interest. It also distorts price signals, which can lead to inefficient consumption decisions and higher overall costs for some customers and for the utility itself in the long run.

Additionally, the selection of a single schedule such as Schedule 8 to serve as the Middle Point, and rounding of the D-Values, seems arbitrary and could distort the results.

Q. Is there an alternative method to spreading revenue requirement across rate classes that addresses your concerns?

A. Yes. On page 2 of DPU Exhibit 11.2 DIR-COS, I provide an example of a rate spread methodology that Ms. Lee Smith on behalf of the Division has recommended in past RMP rate cases. This method, which I identify as the Previous DPU Staff-Recommended Rate Spread Model (or "Staff Rate Spread Model"), is applied to the Company's allocated COS results below.

1. The goal of the method is to set each rate class's targeted rate increase, shown in Column F of the exhibit, to match that necessary to reach allocated COS, but is subject to constraints, namely:
    a. A cap and floor on revenue increases, if needed for gradualism. For the purposes of the exhibit, a cap of 8% and floor of 0% target rate increases were selected to match the Company's methodology.
    b. The additional constraints on Special Contract customers discussed above are preserved in the exhibit.
    c. Schedules 21 and 31 have rate increases equal to the increase for Schedule 9, which is also the same as the Company methodology.

2. Because of the imposition of the constraints, the target increases of the other rate classes must be adjusted away from allocated COS so that the total increase in revenues meets the target amount. This adjustment factor is shown in Column E and is calculated to be the same percent change in revenues for each rate class affected.

Q. How do the two methods compare?

A. The third page of the exhibit provides a comparison and shows the DPU Staff Rate Spread Model provides results closer to allocated COS. However, the Company's methodology could also get closer to allocated COS if the adjustment to the deviations from the average increases was closer to 1 than 0.25.

Q. Are you recommending an alternative rate spread based on your analysis of the Division's recommended revenue requirement, and Ms. Smith's modifications to the COS study?

A. Yes. The Division is recommending a revenue requirement that would result in $5.086 million lower revenues than are currently collected in rates, or a total RMP Utah revenue requirement of $1.879 billion.

There are also differences in allocated COS as described in Ms. Smith's testimony.

The combined effect of these adjustments, particularly the lower revenue requirements, offers a greater ability to move each class closer to its allocated COS while minimizing customer impacts.

Q. What do you recommend in terms of rate spread?

A. Using the approach described above, I created a proposed rate spread shown in Table 5 below. The need for a cap on rate increases was not necessary as all target rate increases are under 8%. Because there was no need for a cap, I also declined to use a floor on rate increases and instead moved all rates as close to their allocated COS as possible. With this approach, I recommend that the residential class as a whole receive a revenue requirement increase of 3.29%, or $21.8 million more than is collected in current rates.

This approach provides better price signals to customers. It furthers the objectives that rates reflect cost causation, equity and economic efficiency.

Table 5 – DPU Staff-Recommended Class Revenue Requirements Based On Company Revenue Requirement Reduction Of $5.086 Million

Line No.	Schedule No.	Description	Annual Revenue	Total Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues	Revenue Adjustment	Target Increase	Target Revenues	Increase in Revenue
1	1	Residential	661,595,338	682,976,484	21,381,146	3.23%	0.06%	3.29%	683,389,204	21,793,866
2	6	General Service - Large	520,951,037	479,887,586	(41,063,452)	-7.88%	0.06%	-7.82%	480,234,224	(40,716,813)
3	8	General Service - Over 1 MW	162,435,073	159,831,397	(2,603,676)	-1.60%	0.06%	-1.54%	159,940,295	(2,494,778)
4	7,11,12	Street & Area Lighting	12,123,900	10,341,236	(1,782,666)	-14.70%	0.06%	-14.64%	10,349,548	(1,774,352)
5	9	General Service - High Voltage	274,874,421	296,550,807	21,676,385	7.89%	0.06%	7.95%	296,738,313	21,863,892
6	10	Irrigation	13,948,796	14,890,298	941,502	6.75%	0.06%	6.81%	14,899,286	950,490
7	15	Traffic Signals	682,028	638,531	(43,497)	-6.38%	0.06%	-6.32%	638,952	(43,076)
8	15	Outdoor Lighting	1,234,602	900,662	(333,940)	-27.05%	0.06%	-26.99%	901,434	(333,168)
9	23	General Service - Small	137,738,937	130,737,001	(7,001,934)	-5.08%	0.06%	-5.02%	130,830,143	(6,908,794)
10	SpC	Customer 1	27,176,952	31,199,085	4,022,133	14.80%		-0.27%	27,103,591	(73,361)
11	SpC	Customer 2	35,062,890	34,784,964	(277,926)	-0.79%		0.00%	35,062,890	0
12	21	Electric Furnace	453,785					7.95%	489,880	36,095
13	31	Back-up, Maintenance, & Supplementary	4,219,468					7.95%	4,555,090	335,622
14	SpC	Customer 3	28,644,835					7.95%	30,923,285	2,278,450
15		Total Utah Jurisdiction	1,881,142,062	1,842,738,049	(5,085,927)	-0.27%			1,876,056,135	(5,085,927)

Q. Have you designed rates that will collect the revenues resulting from this rate spread, and calculated corresponding bill impacts?

A. Yes, for all of the major classes. The rate spread and corresponding rates are attached as DPU Exhibits 11.3 and 11.4 DIR- COS. Associated bill impacts are presented in DPU Exhibit 11.5 DIR- COS.

Q. What if the DPU Staff revenue requirement is not approved, should the Staff Rate Spread Model still be used to develop the rate spread?

A. Yes. I prepared a second case based on the DPU Staff-recommended allocated COS study results, but which assumes the Company is awarded a rate increase of $21.88 million, reflecting a common stock return on equity of 9.8% for an overall weighted average pre-tax cost of capital of 10.67%.

Q. In that case, what would the DPU Staff recommended rate spread look like?

A. Using the same Staff Rate Spread model, the table below presents the results.

Table 6 – DPU Staff-Recommended Class Revenue Requirements Based On Company Revenue Requirement Increase Of $21.878 Million

Line No.	Schedule No.	Description	Annual Revenue	Total Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues	Revenue Adjustment	Target Increase	Target Revenues	Increase in Revenue
1	1	Residential	661,595,338	693,523,302	31,927,964	4.83%	0.06%	4.89%	693,949,986	32,354,648
2	6	General Service - Large	520,951,037	487,031,191	(33,919,847)	-6.51%	0.06%	-6.45%	487,351,770	(33,599,267)
3	8	General Service - Over 1 MW	162,435,073	162,132,576	(302,497)	-0.19%	0.06%	-0.13%	162,224,555	(210,518)
4	7,11,12	Street & Area Lighting	12,123,900	10,456,458	(1,667,444)	-13.75%	0.06%	-13.69%	10,464,266	(1,659,634)
5	9	General Service - High Voltage	274,874,421	300,377,559	25,503,137	9.28%	0.06%	9.34%	300,548,787	25,674,366
6	10	Irrigation	13,948,796	15,118,895	1,170,099	8.39%	0.06%	8.45%	15,127,524	1,178,728
7	15	Traffic Signals	682,028	646,949	(35,079)	-5.14%	0.06%	-5.08%	647,384	(34,644)
8	15	Outdoor Lighting	1,234,602	911,037	(323,565)	-26.21%	0.06%	-26.15%	911,758	(322,844)
9	23	General Service - Small	137,738,937	132,723,338	(5,015,597)	-3.64%	0.06%	-3.58%	132,808,432	(4,930,505)
10	SpC	Customer 1	27,176,952	31,601,703	4,424,751	16.28%		1.16%	27,492,526	315,574
11	SpC	Customer 2	35,062,890	35,178,915	116,025	0.33%		0.00%	35,062,890	0
12	21	Electric Furnace	453,785					9.34%	496,170	42,385
13	31	Back-up, Maintenance, & Supplementary	4,219,468					9.34%	4,613,583	394,115
14	SpC	Customer 3	28,644,835					9.34%	31,320,377	2,675,542
15		Total Utah Jurisdiction	1,881,142,062	1,869,701,923	21,877,947	1.16%			1,903,020,008	21,877,946

Q. Please describe the results.

A. A comparison between Table 5 and Table 6 reveals that with the higher, alternative case revenue requirement, class target revenue requirements shift. The target increase in residential revenues increases from 3.29% to 4.89%. General Service Small, General Service Large and Over 1 MW customers will still see lower rates than at present, but less of a reduction with the higher, alternative case revenue requirement. General Service High Voltage and Irrigation customers would see higher target rate increases under the higher, alternative case revenue requirement, but the increases are still less than 10%. Lighting customers of all sorts would still see rate decreases.

Q. Does the Division recommend rates that reflect full movement towards these allocated COS results?

A. Yes. As discussed previously, to do otherwise would continue a practice where class revenue requirements do not reflect allocated COS. This would result in a failure to achieve rates and revenue responsibility reflecting cost causation, equity and economic efficiency.

The results using the DPU-recommended revenue requirement and allocated COS study indicate that while there are moderate shifts affecting a number of classes including residential, there is not so much dislocation as to cause such severe cost impacts that movement toward allocated COS could be termed unjust or unreasonable.

The results using the higher, intermediate revenue requirements do cause further dislocation if rates were adjusted immediately.

Q. Is the Division recommending any limiters to the revenue requirement shifts?

A. The Division does not foresee the need to artificially restrict movement from current rates to allocated COS rates, and would argue that a full, “overnight” transition is possible if its recommended revenue requirement is approved by the Commission. This would further the objective of cost-based rates, equity and economic efficiency, while balancing customer impacts and ensuring adequate revenues.

If the Commission approves something like the higher, alternative revenue requirement increase, and the shifts in revenue requirement responsibility were deemed by the

Commission to be too harsh using an overnight transition, it could order a phase-in of from 2-3 years, or over a period between now and the next RMP General Rate Case and Rate Design filing.

Q. Have you also designed rates that will collect the revenues resulting from this additional rate spread case?

A. Yes, for all of the major classes. The rate spread and corresponding rates are attached as DPU Exhibits 11.6 and 11.7 DIR- COS. Associated bill impacts are presented in DPU Exhibit 11.8 DIR- COS.

D. Residential Energy Rate Design

Q. After applying the customer charge, minimum bill, and net metering charge how does the Company design energy rates for the residential class?

A. The Company increases the rates in each energy block by an equal percentage such that the desired overall rate increase is obtained.

Q. What are your concerns with the Company's method of designing energy rates?

A. I am concerned about the high summer tailblock rate for the residential classes. The Company's method would increase the difference between the rate in the tailblock and first block even further at a time when usage per customer is generally flat or trending downward.

Because the Company did not file a Utah-specific marginal cost study, increasing the differential is not supported.

Q. Do you have any recommended changes to this method of designing energy rates?

A. Yes. I recommend an alternative method that takes the desired increase to energy rates and divides it by the total kWh billing determinants for the residential classes, which I will refer to as the DPU Staff Rate Adjustment Model ("Staff Rate Adjustment Model"). This number should be added to the existing rates, so that the absolute differences between the rates in the different blocks are preserved. The resulting impact to energy rates of Schedule 1 customers is shown in the table below, which compares the rates obtained with RMP's method and the rates obtained with the Staff Rate Adjustment Model. In both cases, the numbers shown in the table assume the DPU Staff-recommended revenue requirement reduction. This shows how the spread between the blocks is lower with the Staff Rate Adjustment Model.

Table 7 - Comparison of residential rates using two different energy rate design methods. Reflects DPU-recommended revenue requirement and DPU Staff-recommended rate spread.

Schedule No. 1- Residential Service				
	Forecasted kWh	Present Rate (¢/kWh)	Proposed Rate with RMP Method (¢/kWh)	Proposed Rate with DPU Staff Method (¢/kWh)
Summer Season				
First 400 kWh (May-Sept)	1,274,636,742	8.8498	9.1495	9.1865
Next 600 kWh (May-Sept)	1,040,456,011	11.5429	11.9337	11.8796
All add'l kWh (May-Sept)	358,873,906	14.4508	14.9401	14.7875
Winter Season				
First 400 kWh (Oct-Apr)	1,613,094,234	8.8498	9.1495	9.1865
All add'l kWh (Oct-Apr)	1,704,644,903	9.8913	10.2262	10.2280

Q. How have you proposed to adjust rates for the non-residential classes?

A. I have used the Company's methodology for setting the other rates, which generally involves uniform percentage increases (or decreases) to customer, energy, and demand rates that preserves the existing structures. DPU Exhibit 11.4 DIR- COS provides the rate schedule adjustments for these non-residential classes.

E. Schedule 15 Revenues

Q. Please describe the rate classes in Schedule 15.

A. Schedule 15 includes two types of lighting customers: traffic signals and overhead lighting customers. Both are separately allocated costs in the Company's allocated COS study.

Q. Please summarize the Company's proposed rate increases for each type of Schedule 15 customer.

A. The Company proposes a 7.09% rate increase to traffic signal customers, but no rate increase to overhead lighting customers. This is based on the allocated COS results and is summarized in the table below.

Table 8 - Summary of allocated COS study results and proposed rate increases for Schedule 15 customers.[9]

	Annual Revenue from JRS-1	Total COS	Increase (Decrease) to = ROR	% Change from Current Revenues	Proposed Rate Increase
Schedule 15 Traffic Signals	536,865	644,589	107,724	20.07%	7.09%
Schedule 15 Overhead Lighting	1,379,767	939,412	(440,355)	-31.92%	0%

Q. What issue did you find with regard to the revenues for Schedule 15 customers presented in RMP's Exhibits?

A. I discovered a discrepancy in the revenues reported in the allocated COS results presented in RMP Exhibit JRS-1 and the rate design model presented in RMP Exhibit JRS-4. The difference is shown in the table below. The Company confirmed that the revenues in the allocated COS study presented in JRS-1 are in error, but that the revenues

[9] Exhibit RMP JRS-1, page 2, lines 7-8 and Exhibit RMP JRS-4, page 1, lines 28-29.

in JRS-4 are correct.[10] Note that the total revenues for Schedule 15 are approximately the same in each Exhibit.

Table 9 - Discrepancy in Revenues Reported for Schedule 15 Customers.

	Revenues Reported in JRS-1	Revenues Reported in JRS-4
Schedule 15 Traffic Signals	536,865	682,028
Schedule 15 Overhead Lighting	1,379,767	1,234,602
Total Schedule 15	1,916,632	1,916,630

Q. What are the implications of the error in the Company's allocated COS study?

A. The Company originally reported that traffic signals customers required a large percentage increase in revenues to meet their allocated COS, while the overhead lighting customers were paying significantly more than the cost to serve them on a percentage basis, as is shown in Table 9 above. Applying the correct revenues from JRS-4, the situation changes such that both types of customers are paying more than the cost to serve them. This is shown in the table below. This means the 7.09% rate increase RMP proposes for Schedule 15 traffic signals customers is no longer justified by the allocated COS study results provided by the Company.

[10] RMP Response to DPU Data Requests 49.6 and 49.7.

Table 10 – Allocated COS results using correct revenues for Schedule 15 customers.

	Annual Revenue from JRS-4	Total COS	Increase (Decrease) to = ROR	% Change from Current Revenues	Proposed Rate Increase
Schedule 15 Traffic Signals	682,028	644,589	(37,439)	-5.49%	7.09%
Schedule 15 Overhead Lighting	1,234,602	939,412	(295,190)	-23.91%	0%

Q. **What do you recommend regarding the error discovered in Schedule 15 revenues?**

A. Because all the allocated COS study results incorporating the Division's recommended revenue requirement discussed in Ms. Lee Smith's testimony and all corresponding rate designs prepared for this testimony use the correct revenues for Schedule 15 customers, no further action by the Division is required at this point. I also recommend that RMP address this issue in Rebuttal Testimony, and propose a remedy such that traffic signals customers are not assigned a 7.09% rate increase.

Q. **Does this conclude your testimony?**

A. At this time, yes.