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 Approval of its Proposed Electric Service Regulations, Consisting of a General Rate Increase of Approximately 161.2 Million per Year, and for Approval of a New Large Load Surcharge.	)))))))	**Docket N. 07-035-93** **Division of Public Utilities** **DPU Exhibit No. 9.0R**

Rebuttal Testimony of
Abdinasir M. Abdulle, Ph. D.

COST OF SERVICE AND RATE DESIGN

For the Division of Public Utilities
Department of Commerce
State of Utah

September 3, 2008

Q. Please state your name and business address.

A. My name is Abdinasir M. Abdulle; my business address is Utah Division of Public Utilities, 160 East 300 South, Salt Lake City, Utah.

Q. Are you the same Abdinasir M. Abdulle that submitted Direct Testimony for the Division in this Docket (07-035-93)?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to revise my direct testimony to make consistent with the Docket No. 07-035-93 Commission Order on revenue requirement and cost of capital and to rebut certain comments in the direct testimonies of the following witnesses:

1. Paul Chernick – Committee of Consumer Services (CCS)
2. Dan Gimble - Committee of Consumer Services (CCS)
3. Kevin Higgins – Utah Association of Energy Users (UAE)
3. Maurice Brubaker – Utah Industrial Energy Consumers (UIEC)

Comments on Mr. Chernick's Testimony

Q. Are you familiar with any work done earlier to determine what the appropriate demand-energy split should be?

A. Yes. In Docket No. 97-035-01, the Division made a qualitative argument in support of its recommendation for the Commission to adopt the 75%-25%

demand-energy classification that the Commission has adopted. On page 79 of the Commission Order, Docket No. 97-035-01, the Commission stated:

> We conclude that the appropriate allocation factor for production and transmission plant costs is composed of twelve coincident peaks, 75 percent demand and 25 percent energy.

Later, the Company performed a stress factor analysis which came to the conclusion that the 75% demand and 25% energy split is most appropriate.

Q. Could the appropriate demand-energy split costs of generation plant be quantitatively determined?

A. Yes. There are a number of methods used to estimate the energy-related portion of generation plant cost. One of them is the peaker method used by Mr. Chernick. Another one is the stress factor analysis which was used by the Company earlier to prove that the appropriate demand-energy split is 75% demand and 25% energy.

Q. Which of these two methods produce more reliable results?

A. I don't know. Neither the Division nor Mr. Chernick performed a comparison of the two methods. However, the Division believes that the stress factor analysis is more rigorous than the method used by Mr. Chernick. There are a number of relevant factors that are considered in stress factor analysis that Mr. Chernick did not consider in his peaker method. These factors include loss of load probability, monthly reserve margins adjusted for maintenance, monthly reserve margins adjusted for capacity costs, and the probability of contribution to peak. Therefore, the Division believes that Mr. Chernick did not provide enough evidence to support his proposed changes of the demand-energy split.

Q. Could you comment about the impact of changing Rocky Mountain Power's Factor 10 (the demand allocated portion of fixed plant cost) from 75% to 50% on the rate spread?

A. Yes. On Table 1, page 10, of his direct testimony, Mr. Chernick shows that if the demand energy split of the generation plant costs is changed from 75% demand related and 25% energy related, to 50% demand related and 50% energy related, about $8.5 million will be shifted off of Schedules 1, 6, and 23 and about $3.8 million will be shifted onto Schedules 8 and 9.

Q. How would these numbers change if the COS is updated with the Commission Order of Phase I of this case?

A. A shift of $7,088,395 million dollars from Schedules 1, 6, 23 and 25 will occur and $3,658,988 will be shifted onto Schedules 8 and 9, 10, and (7, 11, 12, 13).

Q. What is the Division's recommendation regarding Factor 10?

A. Based on Mr. Chernick's analysis in his direct testimony, which was later verified by the Division, it is apparent that any change in the demand allocated portion of fixed plant cost (F10), will result in significant shifts of the fixed plant costs between the different service classes. Most of these costs will be shifted onto Schedules 8 and 9 and away from Schedules 1, 6, and 23. Since this analysis was based on the peaker method and it has a substantial adverse impact on some of the

Schedules, the Division recommends that the Commission order the Company to convene a study group to address what the appropriate demand allocation portion of the fixed plant cost should be. This working group should compare the different methods of estimating the energy-related portion of generation plant cost, including the peaker method and the stress factor analysis. This group could also examine several of the issues that I will identify below as needing further study.

Q. In his direct testimony Mr. Chernick also proposes to change the demand allocated portion of firm non-seasonal purchases (F87) from 75% to 25%. Do you agree with this proposal?

A. No. As is indicated in Mr. Chernick's direct testimony (page12, lines 247 and 248) and as was later verified by the Division, Changing F87 from 75% to 25% will shift approximately $13 million off of Schedules 1, 6, and 23, and approximately $5.5 million onto Schedules 8 and 9. Using the COS model updated with the Commission Order of phase I of this case, approximately $2,229,074 will be shifted from Schedules 1, 10, and 23 and $1,489,330 onto Schedules 8 and 9.

Given the relatively small rate increase ordered by the Commission in Phase I of this case (about $36 million), the cost shifts proposed by Mr. Chernick are significant. These cost shifts between the classes of service are generally in favor of Schedules 1, 6, and 23 and against Schedules 8 and 9. These impacts are exacerbated by Mr. Chernick's proposed changes in the allocation of firm sales revenue, classification of the transmission plant and the classification and allocation of distribution costs. The Division believes that changes in the classification and allocation methods that have this level of impact should be carefully looked into and discussed by the interested parties in this case. Particularly, when the changes in the classification and allocation factors are not consistent with the way it is done at the inter-jurisdictional level. Therefore, the Division recommends the Commission direct the Company to include these issues in the work of the group described above.

Q. Did the Commission express preference as whether or not cost of service decisions be applied consistently at the jurisdictional and class levels?

A. Yes. In its Report and Order (Docket No. 97-035-01, p.113), the Commission stated

> We also want to insure that these fundamental cost-of-service decisions are applied consistently at interjurisdictional and class levels.

In that same page of the Commission Order, the Commission also states that "In our view, these presumptions must hold unless good and sufficient cause shows otherwise."

This demonstrates the Commission's desire to see the cost of service decision applied consistently at the inter-jurisdictional and class levels unless there is a strong evidence to do otherwise. As I indicated earlier, in the Division's opinion, Mr. Chernick did not provide enough evidence to warrant applying different demand-energy split at the inter-jurisdictional and class levels.

Q. What demand-energy split of the generation plant cost is applied at the Inter-jurisdictional level?

A. It is 75% demand and 25% energy.

Q. On Page 28, Line 573, Mr. Chernick, indicated that since the irrigation load research resulted in a large discrepancy between the sample and actual usage, the data should not be relied upon to support a major cost allocation action. Do you agree with this assessment and conclusion?

A. Though the Division did not perform an in depth analysis of the irrigation load research data, the Division looked into the analysis that Mr. Chernick performed on these data. The results of his analysis indicate that there is a large discrepancy between the sample and actual usage. If he is correct, there may be a legitimate concern of relying on the irrigation load data to increase rates for the irrigation class relative to the jurisdictional average. Therefore, without taking a position on the quality of the irrigation load research or data, the Division is proposing an alternative rate spread and rate design for the irrigation class than that presented in direct testimony. Details of this alternative proposal are described below.

Q. On Page 34, lines 722 to 725, of his direct testimony, Mr. Chernick indicated that by removing the costs of service drops from the calculation of the residential customer charge, the customer charge will become $2.40 per month. Do you agree with this?

A. No. Mr. Chernick argued that, in the case of multi-family housing, each customer will share a service drop with other customers. According to Mr. Chernick, the cost of the service drop varies with the load of the building and not the number of customers, and therefore does not belong in the customer charge. He then went ahead and calculated the customer charge without service drop costs and found it to be $2.40 per month.

The problem with this is that, even if you agree that the service drop cost for multifamily dwellings is a function of the load of the building and does not belong to the customer charge calculation, the service drop for family houses is still a function of the number of customers and should be included in the calculation of the customer charge. In other words, even if you except Mr. Chernick's argument with regards to multi-family dwellings, there is no rational reason to remove all costs associated with services drops from the calculation of the customer charge.

Q. Do you agree with Mr. Chernick's argument that the service drop for multi-family dwellings is a function of the load and not the number of customers?

A. No. Even if you agree that the service drops for multi-family housing depends on the building, one has to recognize that the load of the building is at least partially a function of the number of customers who are expected to live in the apartment complex. In other words, the load is a function of the potential number of residents in the building. To apply Mr. Chernick's logic to the problem, one needs to estimate what portion of the cost of the service drop in the multi-family houses is attributable to the number of customers and use this in the calculation of the customer charge, which Mr. Chernick did not attempt to do. Dropping the whole cost of the service drop from the calculation is not the correct thing to do.

Q. Can you summarize how Mr. Chernick proposes to establish residential summer tail block rates?

A. Yes. Mr. Chernick's proposal pegs rates for peak summer use with given 3rd quarter market prices at the Palo Verde and Mid-C hubs. Mr. Chernick states that these peak use rates reflect total generation costs that range between $0.11 and $0.12/kWh. His proposal also claims that "marginal" load-related (T&D) would add another couple of cents per kWh.

The problem with this is that it is not clear what is included in the Palo Verde and Mid-C prices and Mr. Chernick made no attempt to at a clarification. Mr. Chernick simply took the weighted average of the on-peak and off-peak prices and added capacity cost and used this number to approximate marginal cost. The inference from this approach is that the index prices do not include any capacity related costs. This is exactly one of the disputes that have risen in the past with pricing qualifying facilities: some parties argue that the index prices include capacity components other parties claim that the index prices do not include any capacity components.[1]

In the market place a firm has to cover its fixed costs in the long run if it is to stay in business. Hence, in the Division's opinion, the Palo Verde and Mid-C prices

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[1] In the context of QF pricing, some have argued that the difference between off-peak and on-peak prices is indicative of the value of capacity. If one agrees with this argument, then Mr. Chernick's weighted average of the two contains at least some coverage for capacity if not complete coverage.

must (at least for some of the time) already contain both energy and capacity components. In other words, over the long-run, the index prices must cover, on average, the seller's variable and fixed costs. Mr. Chernick is assuming that these prices reflect only energy costs. If this assumption is true, then Palo Verde and Mid-C prices would not allow sellers of power from these hubs to cover their fixed costs in the long run resulting in losses that would eventually force them out of the market. By adding a separate capacity amount to the weighted average, Mr. Chernick is potentially double counting the value of capacity in his recommendation.

If we agree that these market prices can be used as a proxy for marginal cost, then the marginal cost would be equal to Mr. Chernick's weighted average \$0.9/kWh.

Q. Does the Division oppose marginal cost pricing strategies?

A. In general, no. The Division does not oppose the principle of using marginal costs as a guide to proper ratemaking. However, the Division has expressed its concerns about the complexity and pitfalls of attempting to approximate true marginal cost pricing. Such strategies are very difficult to implement effectively when the necessary information cannot be obtained or is difficult to obtain and when the required conditions for marginal cost pricing are not met.

Q. What are some of the problems with this approach?

A. One of the key requirements of marginal cost pricing is to determine exactly how costs change with each corresponding unit change in output. However, the proxy prices used in Mr. Chernick's approach do not necessarily represent resultant incremental changes in the Company's cost structure from a related unit change of Company output. In other words, the proposal does not sufficiently demonstrate the degree to which Palo Verde or Mid-C market energy prices are actually related to the Company's additional costs that all purchasers impose on the system by the production of one additional unit of electrical output.[2]

Q. Why are conditions such as this critical?

A. Failure to meet necessary marginal cost pricing conditions can result in negative impacts upon customers. In my discussions on the problem of second best in my direct testimony, I explained how efforts to approximate marginal cost pricing for the residential tail block will potentially lead to undesirable outcomes. In addition, marginal cost pricing not accompanied by optimal production levels based on the same marginal cost principles may not result in an efficient outcome.

Q. Could you briefly explain what the problem of second best is?

A. I did briefly discuss the problem of second best in my direct testimony. So let me elaborate at some length. The primary focus of the theory of the second best is on what happens when the optimum conditions necessary to achieve the first best solution are not satisfied in an economic model. This could happen whenever there are market distortions in the system. This could be, for example, the case of a regulated monopoly. In this case would it be appropriate for the firm to set price equal to marginal cost?

[2] The concept of what constitutes "one additional unit" of electrical output is itself a topic of debate. This issue is discussed at length in my direct testimony.

Generally, when one optimal condition is not satisfied, for whatever reason, all of the other equilibrium conditions will change. Any policy implemented to correct this market distortion will potentially lead to a different equilibrium level that corresponds to a lower level of social welfare. The best outcome could be achieved if all market imperfections are addressed simultaneously.

In this proceeding, the case at hand is trying to increase the residential tail block price to the marginal cost in the long run. If marginal pricing occurs only in the tail block and not in any of the other blocks or Schedules (given that all other residential blocks and the rates of all other Schedules are not priced at the marginal cost), the outcome will likely not be optimal and may actually make some of those affected by this strategy worse off. CCS did not demonstrate how the proposal avoids such outcomes. Neither does CCS show how the proposal will result in a more optimal result.

In summary, the problem with the second best is that policies that are appropriate for first best systems (systems that have no imperfections) do not necessarily work in the second best world. In general, if all rates and Schedules are not priced the same way, implementing marginal cost pricing for one class only will create distortions that lead to a second best scenario where the system could be made worse off. In other words, in a second best world, moving less than all the distortions simultaneously may indeed make the system worse off.

Q. Would you comment on the relationship between marginal cost pricing and optimal output level?

A. Yes. According to economic theory firms base their production level and price on the marginal cost. The firm attempts to determine the output level that maximizes its profit and charges the price that corresponds to that output level. The output that maximizes the firm's profit is the one that corresponds to where the marginal cost equals price. An output level that corresponds to a point where the marginal cost is larger or smaller than the price will result in the firm making below or above normal profit. Normal profit in this case is zero. This implies that the firm must determine the optimal output level and price simultaneously.

In this case, Mr. Chernick is proposing that residential rates need to be based on marginal cost. The problem here is that the determination of the output level in this case was not based on the marginal cost principle and there is no way one could determine whether or not this output level is the optimal output. Hence, the marginal cost that corresponds to this output level may not be the optimal level. This goes back to the problem of the second best that I discussed earlier.

Q. What is the Division's position on Mr. Chernick's proposed "marginal" T & D charge?

A. The Division has similar concerns about the T & D charge. As with the proxy market price approach, this charge does not appear to represent a true marginal cost strategy. The proposal contains no information to show how the change in system-wide T & D costs per each unit of output would be determined or accounted for. Again, without complete information on the nature of how all relevant system costs[3] change with an additional unit of output and then showing how these costs are imposed upon all system users, there is no guarantee that such a price will result in a more efficient allocation of electrical service.

Q. Can you describe some specific problems that may occur with this proposal?

A. Yes. The proposed high tail block rate may have a stifling effect on high use customers who are already making efforts to reduce peak load. Customers participating in the "Cool Keeper" load control program, for example, would be punished if they fall into the tail block. In addition, there are questions about the relevance of such a pricing scheme in periods such as weekends or holidays where residential demand is high, but system demand is low. During these periods, residential customers in the tail block could bear the burden of an on-peak price, assuming that such a price is fixed. In essence, these users could be paying a price significantly higher than marginal cost during off-peak periods.

Another problem with the proposal is that it shifts the risk of rate recovery on to the Company. Usage during the summer months is (in part) driven by the weather conditions. If the temperature, during the summer months of a given year, is mild, then the Company may not be able to collect its allowed revenues. Of course, if the weather is hotter than normal, the Company may over collect its revenues. In other words, attempting to push the tail block rates to an extreme could create unacceptable volatility in the Company's revenues. What is needed

[3] Marginal cost analysis also requires a determination of the relevant marginal costs imposed upon society. These are costs imposed upon society, but not explicitly included in the price of the good produced. The classic example is the "external" cost of pollution.

here is to set the tail block rate in such a way that energy conservation could be achieved while at the same time not pushing all of the rate recovery risk onto the Company.

Comments on Gimble's Direct Testimony

Q. On page 27, lines 786 to 789, Mr. Gimble stated that the tail block rate he proposed (11.806) is the lower end of the marginal generation cost range estimated by Mr. Chernick. Can you comment on the appropriateness of this tail block rate?

A. Yes. As I discussed earlier in my rebuttal testimony, the marginal cost analysis performed by Mr. Chernick is not correct and could not be relied upon. However, the Division concurs with the Committee that properly developed marginal cost information could be used to guide the rate design. Therefore, the Division supports the Committee's recommendation that the Company be required to undertake a marginal cost study to help guide future rate designs.

Q. On Page 26, lines 742 to 743, Mr. Gimble proposed to leave the residential customer charge at $2.00/month and increase the minimum bill to $4.00. Can you comment on this?

A. Yes. The Division believes that there is no cost basis for the Committee's proposed customer charge. Mr. Gimble justifies his proposal on the basis of gradualism and an analysis performed by Mr. Chernick. The Division argues that, in the rate case under Docket No. 06-035-21, the Commission considered striking a balance between the principles of gradualism and cost causation and moved the customer charge from $0.98 to $2.00 per month instead of the recommended

$3.67 per month. This represented a $1.02 (approximately 38% of the gap between $0.98 and $3.67) increase. The Division believes that this was a gradual move of the customer charge and needs to be continued. Leaving the customer charge at $2.00 is contrary to the principle of gradualism. Rather it is stagnation.

Regarding Mr. Chernick's customer charge analysis, it seems that Mr. Gimble is arguing that the $2.40 per month customer charge is the maximum amount it should be. The Division argues that Mr. Chernick' proposal actually represents a minimum customer charge. Therefore, the $2.00 per month customer charge proposed by Mr. Gimble does not even represent the minimum suggested by the Committee's consultant, Mr. Chernick.

Q. Can you elaborate on why you think that Mr. Chernick's customer charge analysis indicates that the residential customer charges should be at least $2.40.

A. Yes. Mr. Chernick estimated that a customer charge of $2.40 per month accurately reflects the costs of minimum-size residential customers in multi-family housing *without the cost of service drops or any adjustment to estimated meter reading costs* (Chernick, Direct Testimony, lines 722 – 725). Mr. Chernick testifies that services for this type of multi-family housing are overpriced, and argues that such residents are subsidizing all other residential customers. It follows, therefore, that the customer costs for residents other than those minimum-size residential customers in multi-family housing should be higher than $2.40. If Mr. Chernick's $2.40 figure represents the minimal customer cost for any residential customer, then the current $2.00 customer charge is too low.

Q. How does Utah's current $2 customer charge compare with similar charges in other states within the Company's service area?

A. The Company's current Utah customer charge is significantly lower than what it charges in other states within its service territory. For example, the current Wyoming residential customer charge is $10.18. The Company proposes to increase this charge to $20 in its current Wyoming rate case.[4] The Company plans to increase this rate to $26 in its next Wyoming rate case filing. A Company survey of eighteen Wyoming utilities indicates that average residential customer charges are about $15 month.[5] Minimum charges for residential services in other states within the Company's service territory are as follows: Oregon has a basic distribution charge of $7.50/month; Washington has a basic charge of $5.25/month; Idaho has a minimum charge of $10.27/month; California has a basic charge of $5.49/month.

Q. Do you have a recommendation about what a reasonable rate of increase for the customer charge should be?

A. Yes. In the previous case, the Company claimed that a customer charge of $3.67 was needed to cover its customer costs. This represented a proposed $2.69 increase from the $0.98 customer charge that was in effect at that time. In the end, the Commission ordered that the customer charge be increased from $0.98 to $2.00. This represented a $1.02 increase. This was approximately 38 percent

[4] See William R. Griffith's Direct testimony, Wyoming PSC, Docket No. 20000-333-ER-8, p. 10.

[5] Id., p. 11.

($1.02/$2.67) of what the Company originally requested. The Division argues that this rate of increase (38 percent) was accepted as reasonable and therefore could be applied as a rate by which the current charge could be increased.

Q. Does this mean that you are no longer testifying in favor of increasing the customer charge to $4.00 as the Company has proposed?

A. That is correct.

Q. Why have you changed this position?

A. We have altered this position largely because of the Commission's revenue requirement order. With an ordered rate increase of $36 million, the residential class' portion of that increase is actually less than the amount that would be collected by increasing the customer charge to $4.00. Even if the customer charge were reduced by enough to equal the class' share of the rate increase, we do not believe that it would be a good policy choice to place all of the residential rate increase onto the fixed charge. A major portion of the increase should be placed on volumetric rates in order to improve conservation and efficiency price signals, as I discussed in my direct testimony.

Q. What would the Division's proposed increase to the Residential customer charge be if you indexed the current charge the 38% customer charge increase from the last rate case?

A. The customer charge would be increased from $2.00 to $2.76. However, for simplicity, the Division recommends the customer charge to be $2.75.

Q. Can you show how you arrived at the proposed $2.76 charge?

A. Yes. In this filing, the Company is proposing a $4.00 customer charge to cover the Company's customer costs. This represents a $2.00 increase from the current $2.00 customer charge. The current charge would be increased by $0.76, assuming that the Company should again receive 38 percent of the proposed hike (0.38 x $2.00 = $0.76). Adding the $0.76 increase to the current $2.00 charge results in a residential customer charge of $2.76.

Comments on Mr. Higgins' Brubaker's Direct Testimonies

Q. What are your concerns regarding Mr. Higgins and Mr. Brubaker's direct testimonies?

A. Mr. Higgins raised a concern regarding how the Company interprets the effect of the Revised Protocol cap on Utah class cost of service. His findings indicate that because of the Company's misinterpretation of the impact of the Revised Protocol cap, the class cost of service model moves approximately $13 million from Utah distribution and transmission systems to the Utah generation system. This resulted in the cost responsibility of Schedule 9 being overstated.

Mr. Brubaker, indicated that the load research samples used by RMP in this proceedings are too old and therefore can not be accepted as representative of RMP's current Utah customers. Mr. Brubaker also indicated that there is a mismatch between the loads used in RMP's class cost of service study and the loads used in the jurisdictional study. Based on these two problems, Mr.

Brubaker concludes that the class cost of service is not reliable and should be used as the basis for rate spread.

The Division agrees that the problem raised by Mr. Higgins along with the problems raised by Mr. Chernick do have a substantial impact on rate spread between the classes of service. For example, if Mr. Chernick's proposed changes to the cost of service model are correct, more costs will be shifted onto Schedule 9 and away from Schedule 1. However, if Mr. Higgins' proposed changes to the cost of service model are accepted, more costs will be shifted from Schedule 9 to Schedule 1. There are many allocation factors in the class cost of service model. Changes to any of these other allocation factors will also have rate spread implications. Therefore, the Division believes that the problems indicated by Mr. Higgins and Mr. Chernick indicate the need for comprehensive study of the class cost of service model. Changing just a few aspects of the model, may result in unfair cost shifting between the classes. Therefore, the Division recommends that the Commission order the Company to comprehensively study the model as part of the broader cost of service study group recommended above.

Regarding, the load research problems for Schedules 1, 6, and 23 indicated by Mr. Brubaker and the load research problems indicated by Mr. Chernick, the Division believes that if their analysis is correct, then there is reason for concern and the class cost of service model should not be used as a guide for spread or design. Therefore, if Mr. Chernick's and Mr. Brubaker's concerns about the load research data are correct, the Division recommends that Schedules receive uniform rate spread and all rate elements for all Schedules increased by an equal percentage.

UPDATES TO MY DIRECT TESTIMONY

Q. Now that the Commission has issued its decision regarding Phase I of this rate case, do you have updates to your direct testimony?

A. Yes. I will update my recommendations regarding the rate spread and rate design.

Q. What rate spread are you recommending?

A. The Division ran the class cost of service model with the modifications ruled by the Commission in Phase I of this rate case. The results of cost of service model run indicate that the ROR index for Schedules 9 and 23 are 0.86 and 0.87, respectively. This shows that both of these schedules are outside of the Commission approved ROR band (0.9 to 1.1) implying that both of these Schedules are earning less than their cost of service and should receive a rate increase more than the jurisdictional average (2.64%). Therefore the Division recommends a 4.14% and 4.46%[6] increase for Schedules 9 and 23, respectively. The Division arrived at these percent increases by balancing the cost causation and gradualism principles of rate design. It will take the rates of these Schedules to their respective cost based rates within two rate cases.

The class cost of service study also suggested a 28.1% rate increase for Schedule 10. However, the Division believes that this increase is so large and needs to be applied gradually to promote customer acceptance and rate stability. Therefore,

[6] COS suggested percent increase for a schedule (5.64% for Schedule 9 and 6.28% for Schedule 23) minus jurisdictional average increase (2.64%) divided by 2 plus the jurisdictional average increase.

the Division recommends an increase of 6.72%[7]. This percent increase will bring revenues from Schedule 10 equal to its cost of service within three years. Again this percent increase balances the gradualism and cost causation principles of rate design.

The impact of the Division's proposed percent changes for Schedules 9, 23, and 10 are that Schedule 9 will pay $2,384,729 more than the Company proposed and Schedule 23 will pay $1,904,099 more than proposed by the Company, whereas Schedule 10 $1,487,393 less than suggested by the COS study. The combined effect is $2,801,435 more than the COS study suggested for these three Schedules. This money will be distributed among those rate schedules that were either over-earning or where earning revenues that cover their cost of service. These schedules include; Schedules 6, 8, and 25.

Further, the COS study indicates that Schedule 6 is over earning (ROR index of 1.18) and should receive an increase less the jurisdictional average.

Based on the above discussion, The Division is proposing the following rate spread for the major classes:

[7] COS suggested percent increase (22.81%) minus jurisdictional percent increase divided by three.

Schedule	DPU Proposed Rate Increase
Schedule 1	2.48%
Schedule 6	1.94%
Schedule 8	2.37%
Schedule 9	4.14%
Schedule 10	6.72%
Schedule 23	4.46%
Schedule 25	2.34%

Q. What is your updated rate design for Schedule 1?

A. The Division's proposed residential rate design is summarized in DPU Exhibit 9.4R. The Division proposes that the Commission increase the customer charge from $2 per month $2.75, keep the minimum charge at its current level, eliminate the CLC, keep the current three-block rate structure and increase the energy block rates in a manner that customers across the different usage levels receive the appropriate price signal. The Division proposes to increase the first ($0.076362) and second ($0.0868612) block price differential from approximately 1 cent to approximately 1.05 cents and to increase the second and third ($0.102443) block price differential from approximately 1.5 cents to approximately 1.6 cents. The Division also proposes the winter energy charge be increased to equal the summer first block energy charge. These changes will allow recovery of the allowed residential revenue requirement.

Q. What is the bill impact of your proposed residential rate design?

A. The bill impact of the Division's proposed rate design is reported in DPU Exhibit 9.5R. This exhibit shows that the bill impact for the Division's proposed summer and winter remains relatively close to one another for all customers at all consumption levels (mostly between 1% to 1.4% for summer and between 1% and 1.3% for winter) up to 1000 kWh. The percentage impact for the customers in the third block is higher than that reported for the other blocks both during the summer (between 1.4% and 1.6%) and the winter (1.3%). This reflects the Division's policy of sending stringer conservation and efficiency price signal to the customers whose usage level exceeds 1,000 kWh while balancing cost causation and the gradualisms principles of rate design. A customer with an average (summer) usage level (858 kWh/month) will see an increase of $0.98 per month during the summer and $0.85 per month during the winter.

Q. What rate design would you propose for Schedule 6 customers?

A. The Division's proposal is summarized in DPU Exhibit 9.9R. In short, the Division proposes that the demand charge be increased by 1.04% and 1.29% during the summer and winter months, respectively. The energy charge should be increased by 3.88% during the summer months and 2.23% during the winter months. This will undo the disproportionately high payment by those low load factor customers that was imposed during the 04-035-42 rate case. This proposal also encourages energy conservation throughout the year, particularly during the summer when it is most needed.

Q. What is the bill impact of your proposal?

A. DPU Exhibit 9.10R shows that the percent bill increase is higher for those customers with high load factor than those with low load factor. This is achieved while encouraging energy conservation and righting the inequity built into the rate design for the low load factor customers from the 04-035-42 rate case.

Q. What rate design would you propose for Schedules 23 (Distribution Voltage – Small Customer) and 10 (Irrigation)?

A. The proposed target revenue for Schedule 10 (Irrigation Service) should receive an increase of 10.16% including its share of the revenue reduction resulting from the increased revenues from Schedules 23 and 9. This in conjunction with the introduction of the new dispatch curtailment option will help the irrigation customers in their bills.

DPU Exhibits 9.11R and 9.12R summarize the Division's specific rate designs for Schedules 23 and 10, respectively. To encourage energy conservation, the Division's rate design proposal for Schedule 23 puts most of the additional revenue on the energy and demand charges on an equal percentage basis. Otherwise, the design remains the same except that is rescaled to reflect the Commission's order on Phase I of this rate case.

DPU Exhibits 9.13R shows the bill impacts of the Division's proposed rate design for Schedule 23. This Exhibit shows that with any given load size, the bill impact increases with the energy consumption level. It also shows that for the same energy consumption level the bill impact increases with load size.[8] This indicates that Division's Schedule 23 rate design discourages unnecessary usage of both energy and demand.

Exhibit 9.14R shows the bill impacts of the Division's proposals for Schedules 10. This Exhibit shows that the Division's proposed rates will have proportionately similar impact on all customers regardless of their consumption level and load size (mostly between 6.5% to 6.9% for all irrigation customers during the irrigation season).

Q. What rate design would you propose for Schedule 9 (General Service – High Voltage)?

A. DPU Exhibits 9.15R summarizes the Division's specific rate designs for Schedules 9. To encourage energy conservation and efficient use of equipment, the Division's rate design proposal for Schedule 9 puts most of the additional revenue on the energy and demand charges on an equal percentage basis. The rest of the Division's proposal rate design concepts remain the same. The Division's proposal is superior to the Company's in that it encourages energy conservation and will help curb the summer peak.

DPU Exhibits 9.16R shows the bill impacts of the Division's proposal for Schedules 9. This Exhibit shows that the bill impacts remains relatively the same

[8] For example, for energy consumption level of 10,000 kWh the bill impact will be 5% for a load size of 20 kW, 6.3% for a load size of 25 kW and 6.7% for a load size of 30 kW.

for all consumption levels and load sizes regardless of what the proportion of the energy consumed during the peak period is.

Q. What rate design would you propose for Schedule 8?

A. The Division's proposal is summarized in Exhibit 9.17R. The Division proposes to collect most of the additional revenue on demand and energy charges on an equal percentage basis. This will encourage energy conservation and efficient use of equipment. The Division also proposes that both the summer and winter differential between the on-peak and off-peak energy rates be slightly increased. Exhibit 9.18R shows the bill impact of the Division's proposed rates for Schedule 8. The exhibit shows that this proposal results in an equal percentage change in customer bills for customers at all consumption levels (2.4% for summer and 2.3% for winter.)

Q. Does this conclude your testimony?

A. Yes.