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, Consisting of a General Rate Increase of Approximately 161.2 Million Per Year, and for Approval of a New Large Load Surcharge		)))))))))	**Docket No. 07-035-93** **Division of Public Utilities** **DPU Exhibit No. 9.0**

Prefiled Direct Testimony of

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COST OF SERVICE AND RATE DESIGN

For the Division of Public Utilities

Department of Commerce

State of Utah

July 21, 2008

I. INTRODUCTION

Q. Please state your name, business address, and employer for the record.

A. My name is Dr. Abdinasir M. Abdulle; my business address is 160 East 300 South, Salt Lake City, Utah 84114; I am employed by the Utah Division of Public Utilities ("Division").

Q. On whose behalf are you testifying in these proceedings?

A. I am testifying on behalf of the Division.

Q. What is the purpose of your testimony in these proceedings?

A. The purpose of my testimony is to present the Division's recommendations regarding intra-jurisdictional cost allocation (i.e., "cost-of-service," or "revenue spread") and rate design or pricing.

II. COST OF SERVICE

Q. What is the function of the cost of service aspect of a general rate case?

A. The revenue requirement portion of the case establishes the total volume of revenues that should be collected in a jurisdiction, given normal weather conditions. The purpose of the cost of service element of a case is to apportion the jurisdiction's revenue requirement among all of the customer, or rate, classes. The final element of a case, rate design, establishes the price schedules for all the rate classes. Those prices, multiplied by the expected sales volume (given normal weather conditions), are designed to yield each customer class's annual service or revenue target.

Q. What are the general principles that guide the cost of service process?

A. The primary objective in Utah has been to have each customer class pay their own way – i.e., to the extent practicable, and not be subsidized by other customer classes. In general, this ordinarily entails paying the full costs, or "cost-of-service," that the class is imposing on the system. Established techniques for measuring service costs entail assigning shares of customer, distribution, transmission, and generation costs according to the relative burdens placed on those cost categories by the customer classes.

Q. Will you now please describe the basic elements and mechanics of a jurisdictional cost-of-service study?

A. Please refer to DPU Exhibit 9.1, which is a reproduction of page 2 of PacifiCorp's Exhibit RMP__(CCP-1S). Columns A and B represent the different rate schedules and customer descriptions. Column C shows the annual revenues generated by the current prices charged to each schedule (given normal conditions). Column D shows the return on rate base earned by each customer group, where the cost of service allocations apply to the Total Utah Jurisdiction Annual Revenues of Column C line 14. Column E is the ratio of each customer group's rate base return of Column D relative to the Total Utah Jurisdiction return (Line 14 of Column D). Column F contains the share of the Utah jurisdiction's costs that are allocated to each of the rate schedules, where the total costs are 1.5% above those produced by rolled-in costs with a target return on rate base of 8.19%. Columns G through K show the functional breakdowns of the total cost of service (Column F) for each customer group. Column L shows the dollar increases or decreases required in order for each rate schedule to achieve the target rate-of-return on rate base. Column M converts Column L figures to average percentage rate increases or decreases.

Q. Do the Column M percentage figures constitute what the Company and the various parties recommend as the individual average rate changes for each schedule?

A. No. Recognizing the inexact nature of utility cost analysis, and in the interest of treating everyone as similar as possible, the general practice in a general rate case is to apply the same average rate increase to every rate schedule. Exceptions are routinely made for schedules that are or would be earning significantly above or below the jurisdiction average. The past general practice has been to give a schedule a smaller increase if its rate-of-return ratio (Column E) exceeds 1.10, and a larger increase if that ratio is below 0.90. Special contract customers (Lines 11-13 in the Exhibit) generally receive rate increases that are negotiated with those customers and approved by the Commission.[1]

Q. What is the origin of the general practice of departing from uniform rate increases when the rate of return ratios deviate from the average by more than ten percentage points?

A. The Commission's Order in UP&L No. 81-035-13 (page 35, dated March 7, 1983) concluded the following:[2]

> The study of cost of service is not an exact science and thus, we find we have no obligation to bring each schedule to the precise results of a particular cost of service study. Dr. Leininger, who testified on behalf of Nucor, indicated that bringing a schedule within plus or minus 10% of Company average rate of return is reasonable. We adopt as a reasonable regulatory objective that each customer schedule over time be brought to within a range of plus or minus 10 percent of relevant cost of service study results.

Q. Rocky Mountain Power proposes that Schedule 23 (General Service Small) and Schedule 9 (General Service - High Voltage) receive the same uniform percentage increase as most of the other rate schedules receive – despite the fact that Schedule 23's and Schedule 9's rate-of-return indices are 0.84 and 0.77, respectively, are smaller than the benchmark value of 0.90. Does the Division concur with the Company's proposal?

A. No. Apparently, the Company is treating Schedules 23 and 9 as those other customer classes that fall within five percent of the jurisdictional percentage change in revenue required to bring the jurisdictional revenue equal to cost of

[1] The rates for the special contract customers will change with rates of the tariffs they are tied to, according to specific contract provisions.

[2] Quoting from then-DPU witness Rebecca Wilson's testimony in Docket No. 01-035-01, page 8.

service. I interpret this as the Company saying that, for example, the average percentage price change required to bring Schedule 23 up to the system target return on rate base (11.2%, Column M) is within five percent of the system average required percentage increase (7.22%), and therefore should receive the standard increase proposed for most of the other customer classes. Actually, an 11.2% increase in Schedule 23 revenues to bring it up to its cost of service would be 55% higher than the overall jurisdictional percentage increase in revenue required to make schedule 23's revenue equal to the cost of serving it. The same is true for Schedule 9. For Schedule 9, the percent increase required to bring it up to its cost of service is approximately 54% higher than the jurisdictional average.

The Company's proposed 7.8% rate change will result in Schedules 23 and 9 customers paying less than the cost they are imposing on the system and other customers will have to cover the revenue shortfall. The Division believes that this inter-class subsidy is violating the equity principle of rate-making and is sending the wrong price signal to the customers in Schedules 23 and 9.

Q. What would a correct price signal be?

A. A correct price signal would be better proportioned to the costs of a given customer's marginal increases in energy use imposed upon the electrical system. To the extent that one customer class is underpaying relative to the others, under-pricing forces other customer classes to bear the additional costs of that increase in energy use. In addition, a correct price signal would value reductions in unnecessary or wasteful use of energy resources that are borne by the citizens of Utah generally, such as depletion of resources, reduction of air quality, increases in fuel commodity costs, etc.

Q. What is the Division recommending as treatment for Schedules 23 and 9?

A. The past general practice has been to give a schedule a smaller increase if its rate-of-return index (Column E) exceeds 1.10, and a larger increase if that ratio is below 0.90. Since the rate of return indices for Schedules 23 and 9 are 0.84 and

0.77, respectively, it should receive a percent increase larger than the required average system percent increase. This will mitigate the inter-class subsidy and will send the correct price signal to the customers on these Schedules. Therefore, the Division recommends a rate increase 1.63 percent more than the jurisdictional increase for both Schedules. That will take the percent rate increase for Schedules 23 and 9 to half way between what the Company is proposing and the increase necessary to bring this class fully in line with the cost of service calculated in Exhibit 9.1. The Division also proposes to spread the revenue difference resulting from the difference between the Company's proposed percent rate increases for Schedules 23 and 9 and those of the Division evenly among the rate classes for which the cost of service study indicated a percent rate increase equal to or less than the jurisdictional average. These rate classes are Schedules 1, 6, 8, and 25.

Q. Rocky Mountain Power proposes that irrigation customers (Schedule 10) receive a 15% rate increase. Would you comment on that?

A. Yes. The cost of service study, in which the Company used the results of its new irrigation load research study, indicates that irrigation rates should be increased by 30.6%. However, the Company decided to cap the irrigation rate increase to little over twice the overall jurisdictional average percent increase (15%). The Division understands that as a result of an agreement of the parties in the Load Research Working Group[3] (which stated that in the absence of new irrigation load research, irrigation customers should receive the overall jurisdictional average) irrigation customers received the overall jurisdictional averages in the last general rate cases.

The proposed 15% rate increase for the irrigation customers, though justifiable under cost causation, violates the regulatory principle of gradualism and will result in customer dissatisfaction. Thus, though the Division believes that each customer should pay its own way, the Division believes, in this case, where the

[3] Load Research Working Group Report to the Commission. July 1, 2002.

cost of service study indicates a significantly large rate increase for Schedule 10, it should be done gradually to be consistent with rate stability and to promote customer acceptance. Therefore, the Division recommends a 10.16% rate increase for the irrigation customers.

The Division's proposal is particularly important in light of the fact that the Company is providing a new option (New Dispatch Curtailment Option[4]) in its Irrigation Load Control Credit program to their counter parties in Idaho for the 2008 season. A similar option in Utah could provide Utah participants with greater dispatch flexibility and more money in the form of participation credits, which would offset the impact of a rate increase.

Q. What is the Division's recommendation regarding the new Dispatch Curtailment Option?

A. The Division would recommend that the New Dispatch Curtailment Option be provided to Utah's irrigation customers regardless of whether the Commission chooses to increase the rates for the irrigation customers by 15%, as the Company proposes or by 10.16%, as the Division is recommending. This option will help mitigate the bill impact of the proposed increase by providing more money to the customers in the form of participation credit. This option will also help shave the summer peak, which is a major concern for Utah.

Q. For Schedule 6, Rocky Mountain Power proposed a rate increase of one percentage point less than overall jurisdictional increase and a uniform percentage increase (6.5%) in demand and energy charges. What is the Division's position on this proposal?

[4] Participant's irrigation equipment will be set-up with an advanced two-way control system which allows the customer to manage regular irrigation turns via internet or telephone. Participants will also have the capability to independently control each pump or pivot to meet their needs. I addition, participant will receive 24 hour notice prior to dispatch and will be able to opt out of five dispatches per season. Under this option Idaho irrigation customers will earn up 200% more in participant credit. A more complete description of this option can be found in the Idaho's Irrigation Tariff.

A. The Division believes that the proposed rate increase of one percent point less than overall jurisdictional average rate increase is cost based and therefore reasonable.

II. RATE DESIGN

Q. What are the Division's Rate Design objectives?

A. Based on the state code, the Division's rate design objectives are for the rates to be stable, simple, understandable and acceptable to the public, economically efficient, to promote fair apportionment of costs among individual customers within each customer class with no undue discrimination, and to protect against wasteful use of utility services (UCA 54-4a-6.)

Q. What are the Division's guiding principles to achieve these objectives?

A. To balance these objectives, Lowell Alt, a former Division employee, developed guiding principles consistent with the Division's statutory obligation. These guiding principles, with some modifications necessitated by the changes in operating conditions, are as follows[5]:

1) *Simple* – Simple rates are likely to be accepted by customers. Tariff descriptions should be clear, unambiguous and understandable by the public.

2) Correct price signal – if rates are correctly based on costs, customers can make the right decision about energy use including energy conservation decisions. A complicated rate that is not understood cannot be a good price signal. Some customer classes are better able to understand complicated rates than others.

3) Multi-part rates – three part rates with customer, energy, and demand components will more fairly apportion the costs among individual customers than one or two part rates. However, a demand component for the residential class is normally not recommended since the added cost of demand meters usually outweighs the benefit of better cost apportionment.

[5] Docket No. 97-035-01, Direct Testimony of Lowell E. Alt, Jr. pages 24-25.

4) *Gradualism* – to promote rate stability and to minimize impacts on individual customers, rate changes should be done gradually.

5) *Marginal and embedded costs* – regulated rates must recover the embedded revenue requirement of a rate schedule. Marginal and average unit embedded costs should be reviewed and taken into account when setting prices.

6) *Customer charges* – costs that generally increase with the number of customers, but are not caused by each customer should be excluded from the customer charge and instead be included within the commodity portion of rates. This customer charge position was stated by the PSC in its Order in Mountain Fuel Case No. 82-057-15.

Q. These principles were developed over ten years ago. Are there any new principles or points of emphasis in the Division's principle?

A. Yes. While not a wholly new principle, in recent years the Division has come to place a greater emphasis on energy efficiency and conservation as important policy goals. This is especially the case in the current economic and policy environment that Utah faces.

This and the other rate cases that PacifiCorp indicates it will file in the near future are largely driven by the need to build new generating facilities and to account for increasing fuel prices. In general terms, there are many conservation and efficiency measures that customers can undertake that can mitigate (if not eliminate) these issues and at a low overall cost. Demand reduction is a cost-effect strategy in an environment of rapidly rising energy costs.

The Division's increased emphasis on efficiency and conservation also follows the increased recognition, both within Utah and elsewhere, that energy use imposes costs upon society generally that are not recovered in customers' rates. While these costs (emissions, for instance) are difficult to quantify at this time, they suggest that an emphasis on cost-effective demand reduction has even greater benefits than those that can be accounted for in first-order economic costs.

Q. What are the Division's recommendations in relation to Schedule 1 Rate Design?

A. The Division recommends an increase in the monthly residential customer charge from $2 to $4, elimination of minimum bill, elimination of the customer load charge, keeping the three tier blocking structure while widening the difference between the top and bottom tiers, and an increase in the summer and winter energy charge differential.

Q. What are the Division's justifications for the increase in the monthly residential customer charge?

A. The Division justifies its proposed increase in the monthly residential customer charge on the basis of costs and fairness.

Q. What is the cost justification for the increase in the monthly residential customer charge?

A. DPU Exhibit 9.2 shows the Division's calculated monthly residential customer charge. This calculation is based on the Division's guiding principles stated earlier and the Commission's accepted methodology for calculating customer charge. The Division's calculations included only those items that the Commission has previously recognized as appropriate to be included in a customer charge.

Q. What specifically has the Commission recognized as belonging in the customer charge?

A. In its Rate Design and Spread Issues Report and Order in Case No. 84-035-01, dated on July 1, 1985, the Commission stated the following:

5. The Commission has previously made the finding (Mountain Fuel Supply Company Case No. 82-057-15) that a customer charge results in the payment by each customer of those costs that he imposed upon the system, which are independent of actual energy consumption during a given month. A customer *of UP&L, who uses no electricity in a given month, must nonetheless have his meter read, be issued a billing statement and have his meter maintained in good operating conditions. Those activities represent costs to UP&L. We find that a customer charge, as opposed to a minimum billing, allows such costs to be recovered reasonably and properly.*

One needs to recognize that the list in the above Commission statement is not comprehensive and the Commission did not intend to make it comprehensive. Rather, the Commission's intent was to include all individual-customer-related costs into the customer charge. For example, the above Commission statement does not include the meter, service drop, and their respective depreciations which all rightfully are costs that the customer imposes on the system regardless of energy consumption.

Q. Why do you think that the Division's proposed increase in the monthly residential customer charge is fair and compatible with energy conservation?

A. Fairness dictates that each customer pays his/her way. By allowing some of the customer costs to be recovered in the energy charge, large customers will have to bear more of the increase in the revenue requirement. This was expected to induce them into conserving energy, particularly during the summer when it is most costly. This was the appropriate policy when a declining block rate was used. However, that policy is no longer in place. The current inverted block residential rate structure is enough to send proper price signals to the large customers, such that they no longer have to subsidize small customers through the small customer charge. For small customers to pay their way and to send them a price signal, it is important to have them pay a residential customer charge equal to the costs each of them is imposing on the system.

Q. Customer acceptance is another regulatory objective. Do you anticipate PacifiCorp customers having difficulties understanding and accepting the customer charge?

A. No. By properly explaining that the customer charge is an attempt by the Company to cover the costs of service drop, meters, meter-reading, and billing - regardless of the level of a consumer's usage - the customers will understand what they are paying for and will accept it. Questar customers, many of whom are also PacifiCorp customers, have long accepted a much higher customer charge than what is proposed here. In fact, the Division regularly receives questions from Questar customers who are also PacifiCorp customers asking about why they are paying higher customer charges for gas than they are paying for electricity.

Q. PacifiCorp's current tariff contains a $3.67 minimum bill for single-phase service that is imposed on customers whose usage in a given month is less than 22 kWhs.[6] The Company is now recommending that the minimum bill be eliminated all together. What is the Division's recommendation on this?

A. The Division supports the Company's proposed elimination of the minimum bill if the Commission finds it to be reasonable and in the public interest to increase the customer charge to its cost-based level. Some background information may be useful to show why the Division supports the proposed elimination of the minimum bill.

Some believe that a minimum bill based on customer costs is an adequate substitute for a customer charge. Such a minimum bill is a good approximation of customer costs for those customers with no energy consumption. After customers reach the threshold of energy consumption where the minimum bill is no longer applicable, the only customer costs they are paying for are the current two dollar customer charge. To assure that these customers, for whom the minimum bill is not applicable, pay for their recognized customer costs, they should be charged with a cost-based customer charge.

[6] ($3.67-$2.00)/$0.075389/kWh = 22.15 kWh, where $0.075389 is the current initial-block energy charge per kWh.

A “rate simplicity” argument can also be made for eliminating the minimum bill element of the Tariff. Rather than calculating the prospective bill by first applying the two dollar customer charge and energy rate times usage, adding the two, and then taking the larger of that sum and the minimum bill, the whole matter of a minimum bill can be ignored completely. Therefore, the Division recommends that the Commission increase the residential customer charge from $2 to $4 and eliminate the minimum bill.

Q. What is the Division's position regarding the blocking structure of the residential rate?

A. The Division believes that the Company's proposed changes to the blocking structure sends the wrong price signal and reduces incentives of energy conservation. Currently, energy consumption during the five month summer season (May – September) is divided into three blocks; the initial block, which covers the first 400 kWhs, the intermediate block, which covers the next 600 kWhs and the tail block which covers all kWhs above 1000kWhs. The Company is currently proposing to reduce the blocking structure into two-tier blocking (less than or equal to 1,000 kWh and greater than1,000 kWh). This proposal provides no additional incentive to customers to conserve energy until their consumption level approaches 1,000 kWh, whereas the current three-tier design encourages conservation as a household's consumption approaches 600 kWh.

Q. Would you please elaborate how the Company's proposed blocking structure is contrary to the conservation principle?

A. Column H of DPU Exhibit 9.3 shows that the Company's proposed prices represent an approximate 0.54 cent price increase for the first 400 kWhs, a 0.48 cent price reduction for the next 600 kWhs, and a 0.83 cent price increase for all additional kWhs consumed. Put differently, the Company's proposed block structure and prices will increase the price for the first 1,000 kWh by about 0.067

cents[7] and about 0.83 cents for all additional kWhs used. These price changes will provide little, if any, extra incentive to conserve energy until consumption levels approach 1,000 kWhs. The Company's proposal is likely to send a price signal to only those customers whose usage level exceeds 1,000 kWh.

One has to notice that the forecasted kWhs above 1,000 kWhs is only 22.4% of the total forecasted kWhs.[8] Thus, the price signal associated with the Company's proposal is focused on just the highest 22% of the total forecasted kWhs. This is not a good way to induce customers to conserve energy.

The Division believes that all customers, regardless of their usage level need to conserve energy. To achieve this, the Division recommends retaining the current three tier-blocking structure remain unchanged, and adjusting the rate for each block be set in such a way that it sends the correct price signal.

Q. What was the Company's justification for the reduction in the number of blocks in the residential rate design?

A. Based on its survey results, the Company concluded that the current three-block rate design was not understandable to the customers and therefore did not bring about a change in customer behavior.

Q. Does the Division agree with the results of the survey?

A. No. The Division believes that the Company drew the wrong conclusion from the results of the results of the survey.

Q. Would you please elaborate this?

A. Yes. On page 8 of his Direct Testimony, Mr. Griffith states:

> The major findings of the study are that most residential customers are unaware of their electric rates and usage. As reported by the survey

[7] The sum of forecasted units of the first 400 kWh and the next 600 kWhs divided by the sum of the revenue changes for these two blocks (1,216,009,604 + 1,068,402,460/ 6,594,420 + (-5,074,912) = .00067).
[8] 659,606,080 / 2,944,018,144 = .224.

> respondents, 67 percent do not know how much energy they use each month, 67 percent do not know when their billing cycle begins and ends, and 86 percent do not know on average how many kWh they use in a typical month. All of this information, plus knowledge of the rate blocks and the amount of energy consumed during the billing cycle at any given point in time, is required to effectively receive a price signal under the current rate design. When asked their preference, only 30 percent indicated that they preferred a tiered rate in the summer and a flat rate in the winter. The majority of customers, 54 percent, preferred a flat rate year round, and 16 percent did not know.

The Division feels that many of the data pointed to in these survey results are not relevant to the essential message of the three-tier system – as a customer uses more, the price will increase. Thus, a customer need not know his or her actual monthly usage, nor when their billing cycle begins, in order to receive a correct price signal. All a customer need know is whether or not he or she has been successful in avoiding the more-expensive price tier.

While the Division agrees that the three-tier block rate system is not as well-known to customers as it should be, we feel that this is largely due to a lack of concerted effort at educating customers about the rate structure and the price signal that it sends. The Company's efforts to educate the customers about the current rate design have so far not worked and need to be reconsidered.

Finally on this topic, the Company suggests that because customers aren't aware of the three-tier system, that a move two two tiers is preferable. However, it does not show how the customer who could not understand the three block rate could better understand a two block rate structure and acquire the other knowledge that the Company indicates is necessary to understand and respond to the rate structure.

Q. Can the lack of the customers responses to the current rate structure be attributed solely to the three block rate design?

A. No. The expected customer response to the tail block can be thought as a function of, among other things, the size of the tail block, customer's knowledge and understanding of the tail block rate, the state and national economy, and customer's income level.

In its response to the Division's data request No. 58.4, the Company indicated they have no information on how much of the response can be attributed to lack of understanding of the three tier rate structure. This shows that the Company has read too much into the results of their survey.

Q. What does the Division recommend regarding the lack of customer response to the current rate design?

A. The Division proposes the Company devote greater resources to the customer education necessary to increase awareness of the block structure to allow customers to be able to respond to the price signals it sends. We note that while the Company has spent money promoting specific DSM programs (e.g. See You Later Refrigerator), there has been a notable lack of broader public education efforts that both promote Rocky Mountain Power DSM programs and energy conservation and efficiency more generally. The three-tier structure is part of the demand side management suite that the Commission has approved. We recommend that the Company develop a program proposal, to be presented the DSM working group and to the Commission, that significantly increases broad customer education, similar to the efforts that have been launched by Questar under its DSM program. As with Questar's program, general education costs can be recoverable – even in substantial amounts – if the total package of DSM program and education, taken together, remain cost-effective.

In addition to the above, the Division also proposes keep the current three block rate structure and to strengthen its message by increasing the price differentials between the blocks.

Q. What is the Division's position regarding the residential customer load charge (CLC)?

A. The Division believes that the CLC should not be adopted because it is unfair to those customers who are likely to pay it, does not encourage energy conservation, and may adversely impact lower income customers who live in energy inefficient homes.

Once a customer exceeds 1,000 kWhs in one of the summer months and the CLC is triggered, the customer will have a reduced no incentive to conserve energy during the remainder of that year, as the customer will have to continue paying the CLC for an entire year (October through September) whether or not they reduce energy usage.

It is similar to a sunk cost where once the customer incurs the charge, the customer will not have an incentive to change their behavior to conserve energy and avoid the charge for that year. On the other, hand a volumetric rate provides the customer with an ongoing incentive to conserve energy. Real time rates provide an even better incentive. If the Company is serious about encouraging conservation, maybe it should look into practical means to introduce real time pricing and a more effective time of day pricing tariff.

Furthermore, the CLC may have unintended consequences for some of the lower income customers live in homes that are energy inefficient. These customers will be adversely affected from year to year as they may be unable to afford making their home more efficient.

The Division believes that the energy conservation objective could be more efficiently achieved through the three-tier increasing block rate design that is currently in place. Most of the revenues that would have been collected through the CLC should be collected through an increase in the tail block rate.

If the Commission decides to accept the CLC, the Division believes that, in order to promote conservation, the CLC should be used to leverage participation of the Cool Keeper program. The Cool Keeper program is a program where the Company controls the residential and small commercial summer peak loads through a Company-dispatched direct load control system. CLC payments should be waived from those customers who participate in the Cool Keeper program. This way the number of customers who will sign-up for the program could be expected to increase and peak-day conservation will be increased.

Q. Rocky Mountain Power is proposing to increase the summer and winter energy charge differential and keep the winter residential energy charge unchanged. Does the Division concur with that proposal?

A. Partially yes. Though one can argue that Utah's loads are both winter and summer peaking, the Division thinks that the summer peaks are higher and more expensive to serve than the winter peaks and therefore create more reason for concern. With that said, the Division supports the idea of an increased summer and winter energy charge differential. However, the Division thinks that the magnitude of the difference should be larger than the Company is proposing so that it could be reasonably expected to induce customers to conserve energy. In addition, the Division believes that the winter energy charge should be increased to equal the summer first block energy charge. This will increase incentive for conservation during the winter as well.

Q. Would you like to propose a rate design for the residential customers?

A. Yes. Based on the above discussion, the Division proposes that the Commission increase the customer charge from its current level of $2 per customer to its cost based level of $4, eliminate the minimum charge, 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 signals. We propose to increase the first and second block price differential from approximately 1 cent to 1.1 cents and to increase the second and third block price differential from approximately 1.5 cents to 2.1 cents. The Division also proposes that winter energy charge be increased to equal the summer first block energy charge. The Division's proposed summer and winter energy charges are $.078072 for the summer first block, $.089302 for the summer second block, and $0.111002 for the summer third block, and $0.078072 for the winter. These changes will allow recovery of the allowed residential revenue requirement. DPU Exhibit 9.4 summarizes the Division's proposed residential rate design.

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 9.5. 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 6% to 9% for summer and between 4% and 9% for winter) except those customers that used 100 kWhs or less. These customers are most probably customers who are using the building as a second home. The percentage impact for the customers in the first block is higher than that reported for the other blocks both during the summer and the winter. This is due to the fact that their bill was small to start with and a small addition on the bill will be a relatively large percent change. A customer with an average (summer) usage level (858 kWh/month) will see an increase of $4.85 per month during the summer. This bill impact that is comparable within all consumption levels while providing proper summer price signal.

SCHEDULE 6

Q. Earlier you stated that you agreed with the Company's proposal to increase Schedule 6 rates by one percentage point below the jurisdictional increase. Do you have any rate design concerns with Schedule 6?

A. Yes. The Division is concerned about the proposed uniform percent increase in demand and energy. The bottom block of DPU Exhibit 9.6 shows that during the 2004 rate case (04-035-42) Schedule 6 energy charge was reduced by 7.2% and the demand charge was increased by 19.6% even though the average increase for this schedule exceeded the system average increase. This resulted in customers with low load factor paying most)or a disproportional amount) of the rate increase for the Schedule. DPU Exhibit 9.6 shows that, as a result of this action, the bills for low load factor customers increased almost twice as much as those for the high load factor customers. The Division sees this as unfair to the low load factor customers and a disincentive to conserve energy. Once customers hit their demand level they will have no incentive to conserve.

During the 06-035-21 rate case, the percent increases in demand and energy were reversed for the summer months but not the winter months. DPU Exhibit 9.7 shows that the summer energy and demand charges were increased by 13.7% and 9%, respectively and the winter energy and demand charges 4.9% and 9%, respectively. The impacts of these changes on the customer's summer and winter bills were approximately the same for all customers regardless of their load factor. Though these changes represent a move in the right direction, the Division does not believe that this goes far enough to encourage conservation during the summer.

The Company's proposed uniform percent increase for the demand and energy in the current case does not seem to close the disparity in the bill impacts between the low and high load factor customers that was created during the 04-035-42 rate case (see DPU Exhibit 9.8). Therefore, the Division proposes to place most of the proposed rate increase in this rate case on the energy charge. This will remove the disparities and encourage ongoing energy conservation, not solely peak reduction.

The Division understands that either the low load factor customers or the high load factor customers will have to pay for disproportionately higher portion of the proposed rate increase depending on whether most of the increase is placed on the energy or the demand charge. Therefore, the Division thinks that it is time rethink Schedule 6 and consider splitting it into two separate rate schedules. In fact, the Division has submitted data requests to the Company to further study the possibility of splitting Schedule 6. The Division proposes That the Commission set up a working group to study this possibility.

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

A. The Division's proposal is summarized in DPU Exhibit 9.9. In short, the Division proposes that the demand charge be increased by 5.5% and 6.0% during the summer and winter months, respectively. The energy charge should be increased by 7.6%. 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 9.10 shows that the percent bill increase is slightly 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.

SCHEDULE 23 and 10

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

A. As I indicated above, the Company proposed 7.8% rate increase for Schedule 23 would result in those customers served under this schedule not paying their full cost of service. Consequently, I propose that these customers receive 9.47% rate increase. This will increase the proposed revenue for this Schedule by $1,593,273 from about $105,275,586 to about $106,868,859.

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 9.11 and 9.12 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 the additional revenue on the energy charges. For Schedule 10, the Division's proposal increases the on-season energy and demand charges. These proposals are superior to the Company's in that it encourages energy conservation and will help curb the summer peak. DPU Exhibits 9.13 and 9.14 show the bill impacts of the Division's proposals for Schedules 23 and 10. Both Exhibits show that the Division's proposed rates will have proportionately similar impact on all customers regardless of their consumption level and load size (mostly between 9% to 10% for Schedule 23 customers consuming more than 100 kWh and 8% to 9% for all irrigation customers during the irrigation season).

SCHEDULE 9

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

A. The Division has suggested a 9.4 percent increase for this customer class. DPU Exhibits 9.15 summarizes the Division's specific rate designs for Schedules 9. To encourage energy conservation, the Division's rate design proposal for Schedule 9 puts the additional revenue on the energy charges. The Division's proposals add to the summer and winter on peak energy charges proposed by the Company by approximately 0.2 cents and 0.07 cents, respectively, and 0.03 cents to the Company proposed off-peak prices. 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 9.16 shows the bill impacts of the Division's proposal for Schedules 9. This Exhibit shows that the larger the proportion of the energy consumed during the peak period the larger the impact. This shows how the Division's proposed rates will encourage energy conservation.

SCHEDULE 500

Q. The Company has proposed that new loads 10 MW or greater be served using a surcharge that it claims more closely reflects the marginal cost of serving new loads. Does the Division agree with that?

A. No. The Division does not agree with the Company's proposed use of marginal cost pricing and the proxy surcharge for a number of reasons. First, the Division has some issues with the concept of marginal cost as it pertains to production of electricity. Second, the division has concerns about the proposed surcharge as a proxy for marginal cost. Third, the Division is concerned about the inequities the proposal will create. Finally, the Division is concerned about the impact of the proposal on the State's economic development.

Q. Would you please briefly describe Rocky Mountain Power's proposed marginal cost pricing?

A. Based on the direct testimony of Mr. Griffith, the way I understand it is that Rocky Mountain Power is proposing a 25 percent surcharge commencing August 2008 which will increase to 30 percent surcharge commencing August 2009 for all new loads greater than or equal to 10 MW.

Q. Would you please explain marginal cost from microeconomic theory point of view?

A. Yes. Marginal cost is the change in total cost resulting from an infinitesimally small change in output. This requires that both input costs and output be infinitesimally divisible. This is often not practical in real work. Therefore, the common practice is to estimate the marginal cost of some increment of output, which really measures the average cost of an additional finite, though potentially large, increase in output.[9]

Total cost is the sum of total variable and total fixed costs. Variable costs, as the name implies, vary with output, while fixed costs do not vary with changes in output, at least not in the short run. Therefore, fixed costs would not be included in the marginal cost in the short run (i.e., the change in fixed cost due to a change in output is zero). However, in the long run all costs are variable costs and, therefore, fixed costs are not included in long-run marginal costs either.

Q. What is the rationale behind marginal cost pricing?

A. The basic economic rationale for marginal cost pricing is efficiency: if, in a competitive market, prices are set to marginal costs, then resources will be efficiently allocated among their competing ends. Said another way, producers maximize their profits if the output of the production activity is set at the marginal cost of that production.

[9] Alfred E, Kahn, "The Economics of Regulation: Principles and Practices," The MIT Press, Cambridge, Massachusetts, 1988, p. 66.

Q. In his Direct Testimony, Dr. McDermott supports the use of marginal cost pricing. Do you agree with his recommendation?

A. From strictly a theoretical point of view, yes. It is a standard concept in microeconomic theory that, in the case of perfectly competitive market, marginal cost pricing sends the appropriate pricing signal (welfare maximizing pricing signal). However, in practice, and in addition to other problems, marginal costs are, at best, difficult to define or measure and are likely to be quite controversial.

Q. What are your concerns about the concept of marginal cost in the case of electric industry?

A. The relevant marginal cost in the electric industry is the marginal cost of the least efficient unit. However, trying to estimate it would require clear definition of the term margin. If we, for instance, define margin as MW of output within a given hour or maintaining production in the next hour at the same level, then the marginal cost would vary depending on, for example, whether the generator needs to start up, has a minimum run time, etc. Hence, if the generator needs to start up during the interval under consideration, then the marginal cost is going to the start up cost. If the generator has a minimum run time, then the marginal cost is the costs incurred during the minimum time. These are just a few scenarios where marginal cost would not be the same.

For example, a similar definition or methodology was employed in a qualifying facilities contract with PacifiCorp. Over the life of the contract, the party and PacifiCorp constantly debated over the definition and measurement of marginal costs to be paid to the QF. The Company and the party recently agreed to abandon the method, moving to a simpler method for pricing and settling outstanding disputes on past payments. It seems ironical given the experience with this contract, that the Company is now proposing a marginal cost pricing mechanism, not for just one customer, but for potentially all of its large industrial customers.

There are several additional problems with marginal costs pricing in practice. First, the concept of marginal cost pricing is based on two broad (and unprovable) assumptions: (1) the resulting allocation of resources is the best of all possible worlds and (2) the distribution of income is either the best to start with or can be redistributed at no cost. These two assumptions, and the implied trade off between efficiency and equity, are political or legislative questions, not economic ones.[10]

Second, even if these two assumptions are accepted, several problems in measuring marginal costs still exist. (1) Marginal costs should reflect **all** marginal costs. This is the familiar problem of externalities. If all costs are not reflected, then the efficiency benefits from marginal cost pricing will not occur. The Division, and several other parties, recently recommended that the Company expand its IRP analysis to include additional externalities. This analysis is incomplete at this time and is, therefore, not available to help evaluate the Company's proposal. (2) Marginal cost pricing will not achieve optimal results if the rule is not uniformly applied. This is known as the problem of "second best." Simply, if every market in the economy is not practicing marginal cost pricing, marginal cost pricing in one industry may produce an inferior result to an alternative pricing scheme.[11] On a local level, if PacifiCorp does not set all of its pricing at marginal costs, setting this one price at marginal costs can potentially produce a worse outcome than would result from the current general practice of setting rates at average costs based on the cost of service study. (3) There is a question whether fixed costs should be included in marginal costs. By definition, fixed costs are not part of marginal costs because fixed costs do not vary with output. As I previously mentioned, fixed costs are a short run concept, all cost in the long run are variable costs. Therefore, prices should be based on long run marginal costs. However, when measuring marginal costs in practice, whether to include fixed costs or not is a measurement decision, not a theoretical decision.

[10] Kahn, p. 67-68.
[11] Kahn, p. 69.

Therefore, the Division recommends that the Commission reject PacifiCorp's proposal at this time and instead, form a working group to discuss this issue further including, any other possible methods of addressing load growth.

Q. Would you please briefly describe Rocky Mountain Power's proposed marginal cost pricing the new loads greater?

A. Based on the direct testimony of Mr. Griffith, the way I understand it is that Rocky Mountain Power is proposing a 25 percent surcharge commencing August 2008 which will increase to 30 percent surcharge commencing August 2009 for all new loads greater than or equal to 10 MW.

Q. Does the Division have any concerns about that?

A. Yes. The Division is concerned about the choice of the 10 MW threshold.

Q. What are your concerns abut the choice of the 10 MW threshold?

A. The 10 MW threshold has been chosen arbitrarily. There is no rationale behind it and it is not clear whether a 3 MW or 30 MW threshold would be more appropriate. An optimal threshold level needs that minimizes the number of customers that take their business elsewhere. This threshold should not be applied only to the new customers but to all those customers with the same load characteristics.

Q. Is the Division concerned about the equity implications of the Company's proposal?

A. Yes. The proposal is discriminatory to customers with large new loads. This discrimination can be justified from an economic point of view. In economics, price discrimination means charging different prices for a product or service to different groups of customers. This is made possible by the fact that the price elasticity of the product or service varies between the groups. It has nothing to do the cost of producing the product.

The basis of the Company's price discrimination is solely the cost of serving the new loads. This is contrary to the economic theory. Therefore, the Division believes that charging two customers with identical load characteristics and usage two different prices based on costs is discriminatory without economic basis and should not be accepted.

Q. What unintended consequences would Commission approval of the Company's proposed Schedule 500 have?

A. The one that instantly comes in mind is that the Company's proposal may have a detrimental effect on the State's economic development. As is indicated by the Company (Griffith – Direct testimony), and the Division agrees with, the marginal cost of serving the addition loads will be higher than the embedded cost of serving the same load. In addition, the marginal cost will vary according to conditions of the least efficient generator. Those customers that will be served by Schedule 500 will have to pay a lot more for the power they need to run their business compared to their counterparts in the State of Utah. This puts them in a clearly disadvantaged position and they will likely opt not to do business in Utah. This will hurt Utah's long run economic development. The Division believes that there is need to better understand the economic development implications of the proposal and therefore proposes that Commission to order a full fletch study on this.

Q. What would the Division recommend in relation to the Company's proposed marginal cost pricing?

A. The Division recommends the Commission set up a collaborative group to study the marginal cost pricing method. Specifically the Division recommends the group to discuss the following issues plus whatever other issues the other parties and the Company deem necessary:

a. The definition of the term marginal.
b. How should the marginal cost value be estimated?

c. Which customer classes should it be applied to?
d. What are its impacts on economic development?
e. What other alternative are there to deal with the rapid new load growth.

Q. Does this conclude your direct testimony?

A. Yes, it does.