- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of PacifiCorp |	**Docket No. 04-035-42**
for Approval of its Proposed Electric Rate |	**Utah Division of Public Utilities**
Schedules and Electric Service Regulations |	**Exhibit No. DPU 8.0**

Prefiled Direct Testimony of

George R. Compton, Ph.D.

For the Division of Public Utilities

Department of Commerce

State of Utah

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I. INTRODUCTION AND QUALIFICATIONS

Q. What is your name, and by whom are you employed?

A. George R. Compton. I am a Technical Consultant for the Division of Public Utilities (UDPU, DPU, or Division) of the Utah Department of Commerce.

Q. What is your education and work experience?

A.. I hold a Bachelor's Degree from Brigham Young University, with majors in Mathematics and Psychology, and a minor in Philosophy. A portion of my undergraduate experience also took place at Stanford. I also earned a Master's Degree at BYU in Statistics, with minors in Psychology and Philosophy. In 1976 I was awarded a Ph.D. in economics from UCLA.

While pursuing that degree I was employed by McDonnell Douglas Astronautics in Southern California, principally as a probabilist. Apart from some part-time teaching at BYU, my entire career since earning the Ph.D. has been spent in utility regulation. For all but two of those years I have been employed by the Division, on whose behalf I have testified numerous times before this Commission in cases involving electric, gas, and telephone utilities. In the two odd years, I was an independent consultant. My clients included UAMPS, UP&L, and U S WEST. The main area of my professional interest has been the application of economics principles to utility pricing and costing. For a number of years I was also the Division's primary cost-of-capital witness. My biggest assignment during the past couple of years has been with the PacifiCorp multi-state process (MSP). Its goal was the development of an interjurisdictional cost allocation approach that would win acceptance by all the jurisdictions served by that utility. Utah and other jurisdictions have already approved the “Protocol” method that came out of that effort. There is optimism that the other jurisdictions will also ratify that method by the end of 2005.

Q. What is your assignment in this case?

A. I will be presenting the Division’s recommendations regarding intra-jurisdictional cost allocation (i.e., “cost-of-service,” or “revenues 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 volumes (i.e., given normal weather conditions), are designed to yield each customer class's annual cost of 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 its own way – i.e., not be subsidized by other customer classes. That 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. Those burdens are calculated using formulas involving weighted customer counts, energy consumption, and demand during peak load hours.

Q. Are those formulas the same as have been used to determine Utah's share of the total recognized PacifiCorp costs?

A. The same formulas – using a current-loads, Rolled-In approach -- have been used the past few years to allocate generation and transmission costs to both the Utah jurisdiction and to the customer classes within our jurisdiction. By contrast, customer and distribution costs are assigned directly to the individual states where those costs are incurred. Various different formulas are then brought to bear for allocating the customer-related and distribution costs to the customer classes within the states.

Q. Assuming that the Revised Protocol is endorsed by all the PacifiCorp states, will our jurisdiction's system cost allocation continue to be based on the familiar current-loads, Rolled-In approach?

A. Under the MSP Stipulation, for the next few years Utah's allocation will be based on the lower of the outcomes of the Revised Protocol or of Rolled-In plus 1.5%. It is expected that the latter will be the lower figure. Following those first years, Utah's allocation will be based on the Revised Protocol, subject to further consensual revisions and subject to continued endorsement by this Commission.

Q. When applied to the intra-jurisdictional cost of service task, do the Revised Protocol (or MSP) approach and the previously adopted Rolled-In method produce similar results?

A. The results are almost identical. (Compare Column M of page 2 of Exhibit UP&L___ [DLT-8] with Column M of page 2 of Exhibit UP&L___ [DLT-9].) The two biggest departures of the Revised Protocol from Rolled-In are the regional treatment of hydro and the state-situs treatment of QFs. Those differences between the Revised Protocol and Rolled-In are irrelevant once costs have been allocated to Utah. In other words, they affect inter- but not intra-jurisdictional allocations. Accordingly, one would expect those two approaches to generate fairly similar intra-state cost of service outcomes.

Q. If there were to come a time when there is a significant disparity between the MSP approach and Rolled-In, which should be used for Utah's revenues spread purposes?

A. Even if it were established that Rolled-In best reflected true cost-causation, there would remain a strong argument for preferring the MSP/Revised Protocol approach over Rolled-In. If the MSP factors are what drive costs to Utah, use of something besides the MSP factors to allocate costs to the customer classes would defeat the primary purpose of customer class allocation, which is to avoid inter-class subsidies. Having said that, I would add that it is most unlikely that Rolled-In will be established as better reflecting "true cost-causation" than will the evolved MSP/Revised Protocol approach.

Q. Why is that?

A. The current Rolled-In approach does little to capture the temporal nature of cost-causation. Loads in low-cost April, for example, are not distinguished from loads in high-cost August. The MSP/Revised Protocol approach incorporates some seasonal elements.

Q. Are you saying that the MSP/Revised Protocol approach represents "true cost-causation?"

A. Not at all, although it should be credited for moving in the direction of capturing more cost-determining elements than does Rolled-In. An important example of a cost-determining element that the MSP/Revised Protocol approach does not now capture is the costing distinction between peaking generation plants and baseload plants, much of whose costs owe to the desire to minimize energy costs. (Currently, 75% of the costs of both kinds of plant are allocated on the basis of monthly peak demands and 25% of the costs are allocated on the basis of energy consumption. An alternative approach seen in the regulatory arena is to allocate 100% of the fixed costs of peaking plant according to peak demands, but only 50% of the fixed costs of baseload plants to demand, with the balance allocated according to energy consumption.) Another concern I have with the Company's MSP/Revised Protocol study is that it yielded a counter-intuitive result for the residential class. Since that class is heavily summer peaking, and since, unlike Rolled-In, the MSP/ Revised Protocol incorporates a seasonal cost element, one would think that the latter would allocate more costs to the residential class than would the former. The reverse happened.

Q. As long as our jurisdiction's revenue requirement is based upon Rolled-In plus 1.5%, can we say that Rolled-In factors are determining Utah's revenue requirement, making it reasonable to also perform our in-state cost-of-service studies on that basis?

A. I would agree, but with one caveat. Questions and concerns -- partly based merely on unfamiliarity -- have been raised about the Company's MSP-based cost of service studies. It will be useful for the Company to continue to perform those studies so that outstanding issues can be resolved and refinements can be made before Utah's revenue requirement is indeed based upon the Revised Protocol -- at which time it would be desirable to also base the in-state cost of service studies on the Revised Protocol formulas.

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

A. Please refer to my Exhibit DPU 8.1, which is a reproduction of page 2 of PacifiCorp's Exhibit UP&L____(DLT-8). Columns A and B represent the different rate schedules and the customer descriptions. Column C shows the annual revenues generated by the current prices charged to each schedule (given normal weather 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 15. Column E is the ratio of each customer group's rate base return of Column D relative to the Total Utah Jurisdiction return (Line 15 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 with a target return on rate base of 8.73%. 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 the 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 analyses, and in the interest of treating everyone as similarly 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 12-14 in the Exhibit) generally receive whatever rate increases that are negotiated with those customers and approved by the Commission.

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 Docket No. 81-035-13 (page 35, dated March 7, 1983) concluded the following:

> 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 of 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. You have described the general policy in the event of general rate increase. What happens when there is a general decrease or refund?

A. They are usually in the form of a uniform percentage decrease applied to all schedules other than special contracts.

Q. I have noticed that PacifiCorp is recommending that the residential class receive the same percentage increase that most of the other classes would receive – despite the fact that the residential's rate-of-return ratio (1.17) exceeds the benchmark value of 1.10. What reason does the Company give for its residential class proposal?

A. Apparently the Company is either interpreting the just-cited conclusion differently (without actually referencing it) or is choosing to ignore it. PacifiCorp implicitly includes the residential class among the "major customer classes which fall within five percent of cost of service unity. . . ." I interpret that to mean that the average percentage price change required to bring the residential class up to the system target return on rate base (i.e., Column M of my Exhibit [DPU 8.1]) is within five percent of the system average required percentage increase, and therefore should receive the standard increase proposed for most of the other customer classes. (In numbers, the indicated 6.50% increase for the residential class is within 5% of the 9.78% overall average proposed increase.)

Q. Are there other reasons for making the residential class increase as high as that of the other major classes?

A. Obviously, to achieve a given jurisdictional overall average, the smaller the increase for the large residential class, the larger must be the increase for all the other classes – and it is the larger increases that generate the strongest level of customer opposition. Another argument can be made on marginal-cost-causation grounds. The standard cost of service analysis used in Utah (but, apparently not in Oregon for intra-jurisdictional cost allocation purposes) makes no distinction between historic loads and the loads whose growth may be causing new, higher-cost facilities to be installed. Since the residential and other central air-conditioning loads are more responsible for the summer peak-driven PacifiCorp cost increases than are other classes, it can be argued that it would be less than fair for the residential class to receive a smaller-than-standard overall increase.

Q. What is the Division recommending as treatment for the residential customers?

A. In the event of a decrease, we would suggest giving the residential class the same percentage decrease as the overall jurisdiction average. In the event of an increase, we are indifferent as to whether that class receives the standard increase or a somewhat smaller one. Frankly, I'm in no position to say that either the plus-or-minus ten percent rate of return index convention or the plus-or-minus five percent percentage change in current revenues convention is, on its face, unreasonable.

Q. Does the Division concur with the Company's other spread proposals, namely that irrigation be given what is essentially the same percentage increase as the other major classes, that Street and Area Lighting be given an increase that is about 50% greater than that of the other major classes, and that the Outdoor Lighting and Electric Furnace schedules be given no increase?

A. We do concur. With the possible exception of the special consideration often given to the irrigation class, those departures from the uniform, across-the-board increases promote the objective of getting the customer classes closer to rate of return parity.

Q. What is the basis for the seemingly preferential treatment for the irrigation class?

A. Giving that class the average jurisdictional increase rather than the larger one called for in the cost of service study is a replication of what was stipulated to in the previous general rate case (Docket No. 03-2035-02). The grounds for that stipulation and for the Company's recommendation in this case was an "agreement of the parties" in the Load Research Working Group's Report to the Commission (dated July 1, 2002) to that effect. The value of the approximately ten-percent concession to the irrigation class is about $1 million per year, which in turn is about one-tenth of one percent of the Utah jurisdiction revenue requirement.

III. RATE DESIGN

Q. What is the primary function of the rate design process?

A. It is to construct prices for each rate schedule that will generate revenues equaling the revenue requirement that has been designated as appropriate for it.

Q. Is there another important function of properly designed rates or prices?

A. There is. It is to signal the customer of the cost burden that his usage, or even his presence as a customer, is imposing on the utility. Since peak usage carries a different burden from average usage, most customer classes see both demand and energy charges (based on separate meterings). Since costs also vary according to the season of the year and the time of the day (in some seasons), most major rate schedules now, or proposed in this case, incorporate seasonal and time-of-day pricing distinctions. All the rate schedules also include a separate charge for recovering customer costs.

Q. What are the benefits of the kinds of cost signals you have just described?

A. There are both economic efficiency and equity benefits from suitably designed price signals. Just as a proper revenue/cost of service allocation avoids cross-subsidization among customer classes, proper rate design avoids cross-subsidies among customers within each class. Customers whose usage, for example, is not concentrated during the high cost periods should not have to subsidize customers whose usage is so concentrated. Also, by sending the customer a correct cost/price signal, you avoid the inefficiency associated with either consuming something whose value is less than its cost (because its price is below its marginal cost), or with not consuming something whose value is greater than its cost (because its price exceeds its marginal cost).

The desire to make prices better reflect time- and season-varying costs was reflected in the challenge to the Schedules 6 and 9 Task Force established pursuant to the Revenue Spread and Rate Design Stipulation approved by the Commission in PacifiCorp's last general rate case (Docket No. 03-2035-02). The Task Force's charge was "the development of cost-based rate designs for Schedules 6 and 9 which send proper signals to manage peak demands on the PacifiCorp Utah system." "Managing peak demands" means that, as much as possible, those responsible for the costs associated with meeting the (growing) peaks are those who pay for them, and that costs of unwarranted capacity expansion are avoided.

Q. What came out of the Task Force effort?

A. The UIEC (Utah Industrial Energy Consumers) consultants, Brubaker and Associates, took the lead by providing a detailed study of the production cost differentials that are seasonally and time-of-day related. While there was not unanimity regarding the conclusions and rate design inferences from that study, nothing comparable was submitted by any of the other participants in the task force. The conclusions from the Brubaker study have been incorporated in the Schedule 6 and 9 pricing proposals of PacifiCorp in this case. The Division strongly endorses those proposals. While Schedules 6 and 9 currently incorporate seasonal *demand* charge differentials, seasonal and time-of-day differentials in the *energy* prices have been lacking.

Q. Given the broad movement towards time-of-day pricing, it is notable that not much has been done in this regard with the residential class. Why is that so?

A. The primary reason is the same as for not placing onto time-of-day rates Schedule 6 and 8 customers whose maximum demands are less that 1MW – that is, that the time-of-day metering equipment and installation costs are substantial relative to the benefits that are now seen coming from such rates. It is our belief that the inverted price schedule for residential customers accomplishes much the same thing as would time-of-day rates.

Q. Please explain.

A. The highest residential price applies to monthly usage in excess of 1000 KWhs for the months May through September, when the forecasted monthly average usage is 17% above the usage in the October through April period. Prorating that differential over the five-month "summer" period yields 391.2 MWhs. Considering that 553.1 MWhs are in the five month tail block, one might infer that much, if not most, of the summer-period increase in consumption due to air-conditioning use finds its way into the highest-price tail block. In other words, the objective of sending the high price signal to the highest-cost use is achieved to a considerable degree with the inverted-block residential price schedule.

Having said that, I would remind you that neither the inverted-block rate structure nor time-of-day rates are perfect. Many summer-period days, i.e. the cooler ones, do not experience high marginal costs during the designated peak-rate hours. Similarly, not all residential consumption that is charged the high tail-block rate is due to air-conditioning. But enough of the high time-of-day load period experiences higher costs, and enough of the tail-block load is during high cost, air-conditioning load hours as to warrant the past and proposed price differentials.

Q. The current summer price differential between the tail block and the intermediate block is 1.4 cents/kWh. Is there an empirical basis for that figure?

A. I believe there is. The Brubaker study found the summer on-peak/off-peak marginal cost differential to be 1.29 cents/kWh. When you take into account that the 1.29 cents figure is an average over the sixteen hour, 7 am to 11 pm period, and that the even higher-cost, true peak period is considerably shorter (i.e., from 10 am to 8 or 9 pm, when air-conditioners are running), then it is easy to conclude that insofar as the tail-block rate targets air-conditioning loads, that the tail-block rate captures the actual cost differential caused by the air-conditioning peak period demand.

Q. What if a residential customer uses a lot of electricity, but it is not due to a heavy air-conditioning load. Isn't the inverted-block rate unfair to such a customer?

A. It could be. For that reason there is an optional residential time-of-day rate schedule. If your customer actually uses much of his power in the off-peak hours, he can take advantage of the favorable option. I would also note that the large, low- or non-air conditioning customer only has to pay the high rate for five months. The rest of the year he pays the standard flat rate that large and small customers alike pay.

Q. PacifiCorp in this case is recommending increasing the monthly residential customer charge from 98 cents to two dollars. What is the Division's recommendation?

A. The Division recommends placing the entire residential rate increase onto the customer charge, up to a total customer charge of $2.50. We believe that such could very well accommodate the entire increase which the Commission orders for the residential Schedule 1.

Q. Is there a cost justification for so much of an increase in the customer charge?

A. There is. My Exhibit DPU 8.2, based on information supplied by the Company in response to our data request DPU 20.1, shows that something over $3.00 can be justified. The accounts shown in that exhibit are consistent with what this Commission has previously recognized as appropriately included in a customer charge.

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

A. Its "Rate Design and Spread Issues Report and Order in Case No. 84-035-01 (dated July 1, 1985) contained 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 imposes 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.

Q. In reviewing your Exhibit DPU 8.2, I notice that you have included service "drops" even though the ruling you just cited does not mention that item. Have you gone beyond what the Commission has recognized as legitimately belonging in the customer charge?

A. I don't believe so. I don't believe the list was meant to be exhaustive. For example, it contains meter maintenance, but not meter depreciation or return on meter plant investment. The principle is clear however. It recognizes costs which *individual* customers impose on the system and which do not depend on usage. Every customer needs some kind of connection to the shared distribution system. That connection is referred to as the "drop," or individual line, that connects the customer's meter to the nearby line (or pedestal) transformer (which is typically shared with two or three other customers).

Q. Would the increase in the customer charge that you are proposing violate the implicit policy of this Commission in the past of encouraging energy conservation by shifting the revenue requirement from a customer charge to the energy charge?

A. That policy first came into being long before we had an inverted-block residential rate structure. We believe that such a structure is currently the most effective way to send a pro-conservation message against heavy use when it is the most costly, i.e., in the summer. But some have expressed concerns that the conservation pendulum may have swung too far, i.e., that large customers have borne too much of the increase in the average, embedded cost burden relative to that borne by small customers. If small customers are going to pay their way, they've got to pay more of their customer costs. Now seems to be a good time for "consolidation" vis a vis the progress we've achieved with regard to the inverted-block residential rate and allow the pendulum to swing back in the direction of spreading the increased cost burden onto small and large customers alike rather than primarily onto the large customers.

Q. Wouldn't raising the customer charge from 98 cents to $2.50 violate the regulatory objective of gradualism?

A. When the customer charge was first introduced, it went from zero to one dollar. Compared to both the last PacifiCorp increase and the increases that have been routine for Questar the past couple of years, the $18.24 annual increase in going from 98 cents to $2.50 would appear to be a very modest. I would also point out that with the suggested elimination of the minimum bill (discussed below), some of the smallest customers would actually receive a billing decrease; and all customers would receive an offset to the higher customer charge in the form of a lower-than-otherwise energy charge.

Q. Customer acceptance is another regulatory objective. Don't customers have difficulty with what is sometimes regarded as "paying something for nothing?"

A. Some do, until the concept is explained to them of the utility having to cover the costs of service drops, meters, meter-reading, and billing, regardless of the level of a customer's usage. Questar customers – most of whom are also PacifiCorp's customers – have long accepted customer charges well above the two dollar range. (Questar's customer charge is currently $5.) PacifiCorp's customers in other States also accept much higher customer charges – averaging well over twice what the Division is recommending in this case. (See my Exhibit DPU 8.3)

Q. How can such large customer charges be justified?

A. Electric utility costs are typically classified as demand-, energy-, or customer-related. Much of distribution costs are not energy or demand related. Local "telephone poles" and even the pole transformers (to which are connected the individual customer service drops) have costs that are not affected by power demand or consumption. Therefore, instead of including those customer-related costs with the demand or energy charges, they are often included with the customer charge. The components of the Utah Commission-recognized customer costs to be included in the customer charge are limited to the service "drop," the meter, meter reading, and billing expenses. In other words, the costs permitted in the Utah customer charge do not include those other, substantial distribution costs that are not affected by energy demand or consumption.

Q. Does the Division subscribe to the notion of including all of the non-demand and non-energy-related costs in the customer charge?

A. No. The energy conservation argument for shifting costs away from the customer charge and onto the energy charge has already been mentioned. There is perhaps an even more compelling argument on equity grounds. While the costs of poles, etc. may not vary with power consumption, it seems fair that large customers should pay for a greater share of their fixed costs than should small customers because the former reap a greater share of the benefits from those shared-use facilities. This fairness objective is achieved by including most of the distribution costs in the energy component of the price structure.

Q. In addition to (or, more accurately, as a substitute for) the 98 cent customer charge, PacifiCorp's current tariff contains a $3.54 minimum bill, which is imposed on customers whose usage in a given month is less than 39 kWhs. The Company is now recommending that the minimum bill be increased to $3.90. What is the Division's recommendation on this matter?

A. Let me first lay out some background. Some opponents of a separate customer charge have viewed the minimum bill that approximates recognized customer costs as an adequate substitute for a customer charge. Actually, such a minimum bill is only a good surrogate for those customers with no energy consumption. Beyond that, low-use customers can be seen as paying the tariff amount for the energy they are consuming and commensurately less for the recognized customer costs that they incur. As customers reach the threshold where the minimum bill is no longer applicable, by and large the only customer costs they are paying for are what are included in the explicit customer charge (i.e., currently $0.98). The upshot is that the only way to be sure that small customers pay for their recognized customer costs is to have a separate charge at that level.

But even before the customer charge reaches the full customer cost level, a "rates simplicity" argument can be made for eliminating the minimum bill element of the tariff. That argument is buttressed by the fact that as the customer charge is elevated, not much is collected from the minimum bill that wouldn't be collected from the combination of the customer charge and the energy usage charge. For example, if the Company's rates proposal for residential Schedule 1 were adopted, less than two hundred thousand dollars would be collected beyond what would be collected by simply applying the customer charge and the initial-block energy rate.

The greater the emphasis on simplicity, the smaller will be the concern about the absence of a minimum bill when the customer charge does not cover the full customer costs. It comes down to a judgement call. It is the Division's recommendation that if this Commission elevates the customer charge to a level near $2, it should go ahead and eliminate the separate minimum bill.

And, if not eliminated, the minimum bill amount should at least not be elevated. Besides the complexity and confusion involved with having a minimum bill in addition to a customer charge, there is at least one problem, per se, with raising the minimum bill. If a customer truly uses no electricity, the current minimum bill already exceeds the customer costs directly attributable to that customer and recognized by the Commission.

I would add that the small amount lost in eliminating the minimum bill, given an increase in the customer charge, is far outweighed by what is gained from doubling the customer charge. While the very smallest customer might then pay somewhat less than his customer costs, many more of the smaller-than-average customers will be paying a bigger share of their customer costs with the higher customer charge than under the status quo. This will enable a “significant” reduction (1.6%) in what would otherwise have to be collected in the energy charges.

Q. Has the Company recognized the merit to eliminating the minimum billing?

A. It has. Its witness, William Griffith, said, “In the future, the Company believes that the minimum bill should be eliminated once a more cost-compensatory Customer Charge is in place.”

Q. Besides better tracking of customer cost-causation, what other advantage, if any, comes from substantially increasing the customer charge?

A. Increasing the customer charge helps stabilize the utility’s revenues. The more that the utility’s fixed costs are covered by fixed charges, the less its profits are affected by changes in consumption due to variable weather patterns.

Q. You indicated earlier that the Division’s recommended increase in the residential customer charge should accommodate the entire revenue requirement increase for the residential class. What is the basis for that projection?

A. There are projected to be 7,538,992 residential Schedule 1 customer-months in the test year. Multiplying that amount by $1.52 (or $2.50 - $0.98) yields $11,459,268, which would comprise a 2.7% increase over the revenues generated by existing rates. The Commission’s adoption of the Division’s revenue requirement recommendation would entail an average 1.6% increase for the Utah jurisdiction. So this Commission could award something considerably above the Division’s recommendation of a 1.6% increase and still not have a residential class increase that was above 2.7%.

Q. If the revenue increase for the residential class exceeds your 2.7% figure, how would the Division then recommend adjusting the residential prices?

A. The Company has recommended a uniform *percentage* increase to the three block rates to accommodate that additional revenue requirement increase. The Division recommends a uniform *cents-per-kWh* increase. While the Company’s recommendation would increase the premium of the tail-block price over the middle-block rate, our’s would keep it the same. Again, our motivation is -- for a season at least -- to not differentially add to the burden borne by the largest residential consumers.

Q. Does that conclude your testimony?

A. It does, thank you.