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June 4, 2010

Public Utility Commission
Attention: Filing Center
550 Capitol Street NE #215
PO Box 2148
Salem, OR 97308

Re: Docket No. UE 215: PGE Request for a General Rate Revision

Dear Commission:

Enclosed for filing is an original and five copies of the City of Portland's Intervenor Opening Testimony and Exhibits COP/101-107 in the above-referenced docket. Exhibit COP/108 contains confidential information and is being filed under separate cover subject to the general protective order issued in this proceeding (Order No. 10-056).

Copies have been served on parties to this proceeding as identified in the attached service list in this matter.

Very truly yours,

Benjamin Walters

Benjamin Walters
Chief Deputy City Attorney

BW:lw
Enclosures
cc: Service List-UE 215

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UE 215
Exhibit COP/100
Witnesses: Gray, Koonce, Nierengarten, and Peters

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

CITY OF PORTLAND

Direct Testimony of Richard Gray, Peter Koonce, Peter Nierengarten and Lon L. Peters

Schedules 32, 83, 85, 89 and 91
Customer Impact Offset

June 2010

Q. PLEASE STATE YOUR NAMES AND QUALIFICATIONS.

A. My name is Richard Gray. I am a Contract Administrator and Senior Management Analyst with the City of Portland's Bureau of Transportation. My qualifications appear in COP/101.

A. My name is Peter Koonce. I am the Division Manager for Signals, Street Lighting, and ITS within the Bureau of Transportation for the City of Portland. My qualifications appear in COP/102.

A. My name is Peter Nierengarten. I am an engineer and the Energy Manager for the Portland Water Bureau. My qualifications appear in COP/103.

A. My name is Lon L. Peters. I am an independent consulting economist, providing services to the City of Portland. My qualifications appear in COP/104.

Q. WHAT ARE THE PURPOSES OF THIS TESTIMONY?

A. The purposes of this testimony are (i) to propose changes in rate design that provide better incentives to reduce load during peak periods and shift load from peak to off-peak periods, and (ii) propose other changes for Schedules 85 and 91 associated with issues specific to those Schedules.

Q. WHAT IS THE MOTIVATION FOR THE FIRST PURPOSE?

A. PGE's 2009 Least Cost Plan and PGE's initial filing in this docket both point to the need for PGE to add generation and transmission capacity to meet peak loads in both the winter and the summer periods. (See PGE/1500, Kuns-Cody/8.) Long-run levelized marginal generation capacity and energy costs are almost two times the level of allocated, embedded costs of generation. (See PGE/1504, Kuns-Cody/4.) PGE also has proposed investments in distribution and customer service, and continues to move ahead with implementing advanced metering infrastructure with the capability to provide consumers with more accurate and precise price signals. PGE both needs demand response and is developing the ability to achieve demand response.

Q. WHAT DO YOU MEAN BY "DEMAND RESPONSE"?

A. There are two basic way to obtain demand response: "programs" and "prices". The former includes pilot projects, for example, that compensate customers for reducing load at PGE's request. (See PGE Schedule 77.) The latter includes Schedule 12, which provides for Critical Peak Pricing if residential customers sign up. Notwithstanding these Schedules, the City's review of PGE's initial filing has revealed broad weaknesses in the price structure, which cumulatively provide inadequate price signals for consumers, and thus are likely to reduce interest in energy efficiency programs.

Q. DOES PGE USE MARGINAL COST PRICING PRINCIPLES GENERALLY?

A. Yes, but in a manner that yields individual charges (customer, demand, and energy) that diverge from marginal costs in different and, in some cases, conflicting ways. PGE's approach begins with estimates or forecasts of marginal costs, and then uses the marginal costs to allocate embedded costs, rather than actually setting marginal prices or charges. See PGE/1500, Kuns-Cody/4-16. Although this is a traditional use of marginal costs in rate-making, some improvements are possible and desirable. We propose changes to PGE's proposed rates to encourage more efficient use of electricity, and to defer or avoid costs of generation and transmission in both the short-run and the long-run.

Q. HOW DOES PGE APPLY MARGINAL COST PRINCIPLES IN THE PROPOSED RATES?

A. Following past practice, PGE uses estimates of long-run marginal cost by function to "scale" embedded costs up or down. In application, some estimates of marginal cost (by function) are greater than the relevant embedded costs, which leads to "positive scaling factors", whereas in other cases the scaling factors are negative (i.e., marginal-cost-based prices are lowered). PGE then makes several adjustments: (a) several charges are fixed values rather than being based on allocated or marginal costs, for various reasons; (b) within-schedule reallocations of costs are based on *ad hoc* rules of thumb; and (c) the overall results are subject to a set of "equity" tests to ensure that no customers are subjected to significantly above average rate increases. The result is a final rate design that deviates from marginal cost pricing in ways that discourage conservation and load shifting, compared with a design that attempts to adhere more closely to marginal cost principles.

Q. HOW IS THIS TESTIMONY ORGANIZED?

A. In the following sections we (1) review general principles of cost allocation and rate design; (2) propose specific adjustments for Schedules 32, 83, 85, and 89 that are based on the general principles; (3) propose other changes to Schedule 91 that are unique to that rate schedule; and (4) propose consideration of the elimination of the Customer Impact Offset in furtherance of the Commission's long-term goal of cost-based rates.

I. Cost Allocation and Rate Design

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In this section, we briefly state and explain fundamental principles of cost allocation and rate design.

Q. WHICH FUNDAMENTAL PRINCIPLES DO YOU THINK ARE INADEQUATELY IMPLEMENTED IN PGE'S INITIAL FILING?

A. We have several concerns with the filing. First, time-of-use (TOU) energy charges are either missing or inadequately justified by PGE. Second, some proposed charges are based on "judgment calls" rather than being based on a measure of cost (embedded allocated, or marginal), even if modified, for example, by the Customer Impact Offset (CIO). Third, despite the fact that PGE projects the need to incur incremental generation and transmission costs that exceed the average cost of these functions, some of the proposed demand charges ($/kW, including Facility) have a flat or declining block structure. Fourth, PGE proposes reclassification of costs from "Facility" to "Customer", which has the effect of reducing demand charges generally, again muting the signal of rising incremental costs for generation and transmission capacity. Fifth, the rate design does not, in general, take sufficient advantage of the capabilities of PGE's new "smart" meters. Finally, the cumulative effect of the proposed Customer, Facility and Demand charges is a shift of costs from "avoidable" to "unavoidable", which is contrary to PGE's expected long-run marginal costs. Furthermore, this rate design mutes "price signals" and thus reduces the incentive of individual consumers to take actions that would help PGE, and thus *all* of PGE's consumers, to reduce its costs in the future.

Q. WHAT ARE YOUR SPECIFIC CONCERNS ABOUT PGE'S PROPOSED TIME-OF-USE ENERGY CHARGES?

A. First, the proposed time-of-use option in Schedule 32 contains TOU energy charges that are not grounded in costs, either marginal or embedded. Second, Schedule 83 simply has no time-of-use energy charges, either mandatory or optional.

Q. PLEASE IDENTIFY THOSE CHARGES THAT ARE BASED ON "JUDGMENT CALLS".

A. In Schedule 32, the proposed Basic Charge is the same as the current Basic Charge, and is "considerably below the marginal customer-related costs". See PGE/155, Kuns-Cody/22. In Schedule 83, the proposed Basic and Distribution Facilities Charges are "fixed values", not tied directly to cost. According to PGE, "[s]imilar to Schedule 32, these basic charges are set considerably below the marginal customer-related costs." PGE/1500, Kuns-Cody/24. In Schedule 85 (Secondary), the Basic Charges are fixed values that are sixteen to twenty times the current values (depending on phase). In Schedule 85 (Primary), the Basic Charges are fixed values that are 4.5 times the current level. Furthermore, "[t]hese customer charges fully recover (subject to rounding) the allocated marginal customer related costs." PGE/1500, Kuns-Cody/27. In Schedule 89, the Basic Charges are about two to nine times the current levels. According to PGE, "[w]e set the Basic Charges for secondary, primary and subtransmission voltage customers at approximately 90% of the marginal-customer-related costs with any under-collection captured by the Facility Capacity Charges." PGE/1500, Kuns-Cody/29. In short, these Basic Charges are not clearly connected to cost recovery in any systematic fashion across rate schedules, and are in some cases significant departures from current charges.

Q. WHICH RATE SCHEDULES HAVE FLAT OR DECLINING BLOCK STRUCTURES?

A. Schedule 32 has a declining block energy price structure. Schedule 83 has a declining block Distribution Facilities Charge and flat Distribution Demand and Transmission Charges. Schedule 85 has a flat structure for Transmission, Distribution

Facilities and Distribution Demand. Schedule 89 has a flat structure for Transmission and Distribution Demand, and a declining block structure for Distribution Facilities. *See* COP/105 which illustrates the inclining and declining block structures of several of PGE's proposed tariffs.

Q. DO ANY RATE SCHEDULES HAVE INCLINING BLOCK STRUCTURES?

A. Yes. Schedule 7 has an inclining block energy charge structure. This is the only Schedule with an inclining block structure.

Q. HOW HAS PGE RECLASSIFIED COSTS?

A. PGE proposes to reclassify Service and Transformer costs from Facility to Customer. See PGE/1500, Kuns-Cody/15. This reclassification increases the Basic Charges ($/customer) and reduces the Distribution Charges (mills/kWh or $/kW).

Q. WHAT IS THE CUMULATIVE EFFECT OF THESE PROPOSALS?

A. By moving costs from "avoidable" to "unavoidable", and by adopting flat or declining block rate structures, PGE is both reducing the incentive to conserve, and ensuring that costs are recovered from charges that customers cannot choose to avoid by changing their behavior. The one rate schedule with an inclining block structure covers about half of PGE's expected load, but is probably the customer class least likely to respond to price signals. Both of these results are contrary to a broad public policy goal of encouraging conservation, energy efficiency, and load shifting, and are contrary to basic economic principles.

Q. PLEASE SUMMARIZE THE BASIC PROBLEM.

A. PGE's overall rate structure, although starting from projected marginal costs, does not yield marginal prices that are anywhere close to long-run marginal costs. Consumers making investments or operational decisions are doing so without adequate information about the long-run consequences of their decisions.

Q. IN GENERAL, WHAT IS THE SOLUTION?

A. First, we need to find a rate design that will provide better incentives for *all* consumers to respond to actual charges in their rate schedules, on a consistent basis across rate schedules. Second, we need to ensure that PGE's legitimate fixed costs are recovered. PGE's cost structure includes a mixture of fixed and variable costs. In the long run, all costs are inherently variable, but in the short run, any response to price signals by customers may erode the recovery of PGE's fixed costs. That is, if customers take actions to shift or reduce load, PGE's revenues may decline faster than PGE's costs, at least in the short run. The basic problem is to find a rate design that promotes customers to take actions to conserve, without undermining PGE's ability to recover its legitimate fixed costs of operation.

Q. PLEASE BE MORE SPECIFIC.

A. Several approaches are possible. First, each rate schedule could contain a larger fixed charge, so that revenues from fixed charges are more closely tied to fixed costs. PGE has adopted this approach in some of its proposed tariffs. However, this approach reduces variable charges, thus reducing the incentive to conserve energy or shift load, and has a disproportionate impact on smaller customers within a given rate class (rate schedule). Second, marginal charges could be raised to provide greater incentives for all consumers, in whatever rate class, to conserve energy or shift load; for revenue neutrality, inframarginal charges would need to be reduced accordingly. Finally, because of potential concerns about underrecovery of fixed costs, *ex post* adjustments to rates could be adopted that would ensure that, over time, PGE's fixed costs are recovered, while separating the recovery of those fixed costs from marginal decisions by customers. This is a form of "decoupling". We propose that the Commission adopt a combination of higher marginal charges, lower inframarginal charges, and an associated decoupling mechanism.

Q. PLEASE DISTINGUISH MARGINAL AND INFRAMARGINAL CHARGES.

A. Marginal charges are those that apply to the last kWh or kW consumed in a given billing period. Specific examples for certain rate schedules are provided in COP/105. Inframarginal charges are those that apply to the first (and sometimes second) block of kWh or kW consumed in a given billing period. In Schedule 7, the only inclining block tariff, PGE has proposed two inframarginal charges (applied to the first and second 500 kWh per month) and one marginal charge (applied to consumption above 1,000 kWh per month). From an economic efficiency perspective, we are concerned about the marginal charge; from other perspectives, such as equity and revenue recovery, the inframarginal charges are also important.

II. Redesign of Schedules 32, 83, 85 and 89

Q. PLEASE DESCRIBE THE PROBLEMS IN THE PROPOSED MARGINAL CHARGES IN THESE SCHEDULES.

A. Exhibit COP/105 illustrates the problem: except for Schedule 7, inframarginal charges exceed or equal marginal charges. Because significant portions of PGE's cost structure have long-run marginal costs that exceed embedded or average costs, this pricing structure is incorrect.

Q. WHAT IS THE RELATIONSHIP BETWEEN PGE'S PROPOSED MARGINAL DEMAND CHARGES AND PGE'S LONG-RUN MARGINAL COST OF CAPACITY?

A. PGE's levelized long-run marginal cost (LRMC) of generation capacity is \$191.18/kW-year, or \$15.93/kW-month. See PGE/1504. This LRMC is driven by PGE's projected need to acquire new generation resources to meet peak loads. In contrast, those rate classes facing demand charges pay between \$3.31 and \$5.71 per kW-month. A customer that shifts one kW from the peak to the off-peak period, or otherwise shaves its peak load, would reduce its own bill by a small fraction of PGE's LRMC of generation capacity, while conferring a benefit on other customers.

Q. WHAT IS THE ANALOGOUS CALCULATION FOR ENERGY?

A. In some cases, the marginal energy charge is greater than the projected marginal cost of energy, whereas in other cases the opposite relationship holds. In part, this is because energy charges in some rate schedules are designed to recover capacity costs and other fixed costs. Our proposals for energy charges here are limited to time-of-use and seasonality.

Q. ARE THESE COST UNITS STRICTLY COMPARABLE?

A. No. However, they provide rough orders of magnitude, and are "conservative" in the sense that marginal transmission, distribution, and customer service costs are excluded from the conclusion that marginal charges are less than marginal costs. In addition, in its original justification for AMI investments, PGE stated that "[t]he primary benefit driver is the cost of avoided capacity." (*See* UE 189, PGE/103, Carpenter-Tooman/ 4 (PGE 103 is attached to this testimony as COP/106)). As this benefit has been identified by PGE as the main source of benefits from AMI investments, and because these investments support improvements in rate design, avoiding long-run capacity costs is a sufficient justification for changes in rate design.

Q. IS THE CITY ABLE TO SHIFT LOAD FROM PEAK TO OFF-PEAK PERIODS?

A. Yes. The best example is the Water Bureau. The City could change the operations of 40 water booster pumping stations that represent over five MW of demand. At many of these pump stations the City has the operational flexibility to shift pumping to the off-peak period. Specifically, peak demand could be reduced during the summer on-peak period by the following amounts at four pump stations: Washington Park, 780 kW; 112th Street, 75 kW; 162nd Street, 75 kW; and Verda Vista, 30 kW. For example, at Washington Park (the City's second largest pump station) the Water Bureau would run three to five pumps during the summer off-peak period to fill storage tanks, and then would try to run only one pump during the peak period. The Bureau would try to limit summer On-Peak Demand to 300 kW in total while allowing "Off-Peak Demand" to rise to 1200-1500 kW, for a total savings during the peak period of about one megawatt. Estimated peak demand reductions would last for all 96 on-peak hours per week during June through September. For the other months of the year, three-quarters of these estimated demand reductions would last for all 96 on-peak hours each week. (On-peak is defined as 6 a.m. until 10 p.m., Monday through Saturday.)

Q. WHAT HAS THE CITY DONE TO MANAGE THESE ENERGY COSTS?

A. There is very little the City can do under the current and proposed Schedules 83, 85 and 89 to reduce its energy costs by changing operations. For example, Schedule 83 currently has no time-of-use energy charges, so there is no energy cost savings to be achieved by shifting to off-peak pumping. Furthermore, the off-peak period is shorter than the on-peak period, so to achieve the same volume of pumped water, more pumps would have to run during the off-peak period than currently run during the on-peak period. This means that shifting pumping load to the off-peak period would actually *increase* the Water Bureau's bill, due to higher demand costs. Proposed Schedule 83 does not provide any incentive to shift load, either.

Q. WHAT ABOUT PROPOSED SCHEDULES 85 AND 89?

A. PGE's proposed rate schedules offer a small reduction in the cost of energy by shifting load from peak to off-peak periods, about 12 mills/kWh. However, the demand charge billing factors in Schedules 85 and 89 are the same as Schedule 83, and the shorter off-peak period means that the increased pumping load at night would more than erase the savings on the energy side of the bill. Thus, these rates provide no incentive to shift load either.

Q. ARE THERE OTHER CITY OPERATIONS THAT COULD SHIFT LOAD FROM PEAK TO OFF-PEAK PERIODS?

A. Once the East Side Big Pipe portion of Portland's CSO project is completed (currently anticipated for late 2011), the City expects to have additional opportunities to change operations to increase energy savings, which may lead to additional demand reductions.

Q. WHY DOES THE PROPOSED RATE STRUCTURE NOT PROVIDE SUFFICIENT INCENTIVES TO SHIFT OR REDUCE PEAK-PERIOD LOADS?

A. There are two reasons. First, the marginal demand charges are too low, relative to levelized LRMC of capacity. Second, the demand billing factors apply during the off-peak period. As noted above, PGE expects to add generating capacity at a levelized LRMC of almost $200/kW-year in order to meet peak loads. Actions by consumers that can defer PGE having to acquire that additional capacity should be encouraged. The proposed rate structure provides no real incentive to shift load, and provides inadequate incentives for customers to make investments in conservation or to permanently change operations to help PGE avoid or defer expected long-run costs in generation and transmission capacity.

Q. WHAT DO YOU PROPOSE?

A. One solution would be to redefine the billing determinant for *all* demand charges so that it excludes all loads during the off-peak period.

Q. WHAT DOES PGE PROPOSE IN THIS REGARD?

A. PGE's proposed rate schedules propose multiple billing determinants, depending on rate schedule. Schedule 83, for example, sets a "Distribution Charge (Demand)", whereas Schedules 85 and 89 set "Distribution Charges (On-Peak Demand)". In addition, all of these schedules contain Facility Charges, which are applied irrespective of time of day and also use a "demand ratchet". Rule B does not provide for time-differentiated demand charges, unlike time-of-use energy charges. Thus, the "On-Peak Demand" charges are also applied during off-peak periods.

Q. WHAT DO YOU PROPOSE INSTEAD?

A. First, all rate schedules with demand charges should have the same definition of demand billing determinants. Second, all demand charges should encourage peak load reductions during PGE's peak period. There are two ways to implement this in practice: coincident billing and peak-period billing. Under coincident billing, the customer's load at the time of the coincident peak on PGE's system would be the billing determinant for all demand charges. Under peak-period billing, the customer's peak load during the peak period would be the billing determinant, irrespective of whether it occurred at the time of PGE's coincident peak load.

Q. WHICH DO YOU RECOMMEND?

A. We recommend peak-period billing for demand charges, and the elimination over time of the demand ratchet for Facility Charges. Coincident peak billing requires customers to guess when PGE's coincident system peak load will occur during any given month or billing period. Although information about the timing of historical system peaks is available, it would be difficult for any customer to depend on guessing to quantify potential savings of shifting or reducing peak load. Peak-period billing, on the other hand, allows the customer to shift load out of the peak period, or shave peak loads, with accurate knowledge of the cost savings. Also, different customers may have different ways to shift load, and they should not be constrained by trying to hit a limited target of PGE's system peak.

Q. WILL THIS REQUIRE CHANGES IN PGE'S BILLING SYSTEMS?

A. We assume so. However, in Docket No. UE 189, the Commission approved PGE's request to add Schedule 111 and recovery the costs of the Advanced Metering Infrastructure (AMI) program. In Order 08-245 (May 5, 2008), the Commission noted at several points the possibility of benefits through changes in rate design and demand response that depend on the AMI program. The Commission pointed specifically to a "second stage" of AMI (post-deployment), in which "the technology may be used dynamically to generate much more substantial benefits through *rate design* and load control applications and other system and operational benefits." (See Order 08-245, p. 9, emphasis added.) In the "Proposed AMI Conditions", attached to Order 08-245, PGE stated its belief "that development of customer demand response capability and additional tools through which customers can increase their energy efficiency are of great value to our customers' and PGE's future." (See Order 08-245, Appendix A, page 10 of 21.) Although PGE committed to filing a critical peak pricing (CPP) tariff in UE 189 (*ibid.*), CPP is not the only possible change in rate design that utilizes the capabilities of AMI. We are simply recommending that PGE use the new ability to separate loads during the peak and off-peak periods, and eliminate off-peak demand charges for those rate schedules with demand charges. As customers respond to this opportunity to shift loads, the "business case" for AMI should improve, because revised pricing structures will help reduce and defer long-term investments in generation and transmission capacity.

Q. SHOULD PGE'S BILLING SYSTEM ULTIMATELY BE SIMPLIFIED BY THIS APPROACH?

A. We think so. For example, if all rate schedules with demand charges have the same billing determinant for all demand charges, and if that billing determinant is set during the current on-peak billing period, the billing should be simplified, compared with the current system that requires multiple demand billing determinants within and across rate schedules.

Q. WHY DO YOU PROPOSE THIS CHANGE IN THE DEMAND BILLING FACTOR WHEN AMI WAS JUSTIFIED IN PART WITH EXPECTED SAVINGS DUE TO DIRECT LOAD CONTROL?

A. Load control programs require both PGE and individual customers to reach agreement on the ability of PGE to control devices on customers' premises, including air conditioning, water and space heat, and standby generation. Negotiating the terms and conditions of such load control, and the corresponding compensation to customers, may be difficult and time-consuming, posing significant transactional barriers. Recovery of the costs of direct load control programs will presumably require additional tariff filings. Changing the demand billing determinant, and informing customers of the change, requires no negotiations or other tariff filings. Customers' responses to the new rate design will not require negotiations with PGE over terms and compensation, or notice by PGE that a critical peak pricing period is approaching.

Q. PLEASE COMPARE YOUR PROPOSAL ON DEMAND BILLING DETERMINANTS WITH SCHEDULE 77.

A. PGE has in place a "demand response" tariff: Schedule 77, the Firm Load Reduction Pilot Program. This tariff only is available to customers served under Schedules 75 and 89. The minimum demand reduction under Schedule 77 is one megawatt per Point of Delivery. The maximum demand reduction under Schedule 77 is ten megawatts. Schedule 77 requires advance notice by PGE (either two or four hours) and a maximum consecutive number of curtailment hours per day (four). None of these limitations applies to our proposal.

Q. WHAT OTHER CHANGES DO YOU RECOMMEND?

A. First, the proposed change in classification of costs from Facility to Customer should be reversed. In addition, marginal charges should be moved closer to long-run marginal costs. One general approach is to establish increasing block charges, such as PGE has in place, and is proposing, for Schedule 7. For test year 2011, we propose that the Facility Charges be modified in an expected "revenue-neutral" fashion for each class.

In part this is driven by the recognition that billing systems are difficult and expensive to modify, so we have tried to use the proposed rate *structure* to the greatest extent possible, but with modified charges *within* that structure.

Q. WHAT FACILITY CHARGES DO YOU PROPOSE?

A. We recommend adjusting Facility Charges such that the sum of all demand charges (Facilities + Transmission + Distribution) in the tail-block equal about 50 percent ($7-$8/kW-month) of PGE's LRMC of capacity, with inframarginal demand charges reduced to achieve expected revenue neutrality within each class. In Schedules 83 and 85, the proposed block sizes should be retained. The inframarginal charges should be recalculated for the final revenue requirement and reduced to achieve intra-class revenue neutrality. In Schedule 89, one additional change would be required because customer sizes are so diverse.

Q. WHAT DO YOU PROPOSE FOR SCHEDULE 89?

A. First, it is important that all customers see a greater incentive to shift or reduce peak loads, irrespective of size. Second, all three voltage levels of Schedule 89 have a very small tail-block Facility Charge. This means that the largest customers in Schedule 89 have the *lowest* incentive to reduce or shift peak loads, and the *greatest* incentive to increase peak loads. As these are likely to be the customers with the greatest knowledge and understanding of their energy costs, this seems to be a perverse result. In addition, these customers are all greater than one MW by definition. The solution is merging the second and third Facility Charge demand blocks.. The charges for this tail-block would be set at $7-$8.00/kW, so that all customers on this revised Schedule 89 would face the same marginal demand charge, and the inframarginal charge adjusted downward accordingly to achieve revenue neutrality within the customer class. For 89-Primary and 89-Subtransmission, this approach may lead to *negative* Facility Charges for the first 1,000 kW. However, this means that the total expected bill for this customer class is the same, while creating a much stronger incentive to reduce or shift peak period loads.

Q. SHOULD PRICES ALWAYS BE POSITIVE?

A. No. Negative prices can be rational in a variety of situations. The most apt example may be "negative salvage value": the need to pay someone to take away an asset that has reached the end of its useful life. Instead of being paid for the asset, the owner must pay someone to remove it. Also, PGE's adjustment schedules contain many charges that can be positive or negative.

Q. ARE THERE ALTERNATIVE WAYS TO ACHIEVE SIMILAR RESULTS?

A. Yes. See Boonin, D.M., "A Rate Design to Increase Efficiency and Reduce Revenue Requirements", *The Electricity Journal*, 22(4), May 2009, 68-78. We are not proposing adoption of the "feebate" approach described by Boonin for this case because it appears to require even more fundamental changes in rate design. Another approach is known as the "rolling baseline rate", which is a form of tiered rates: one charge is set for "baseline consumption" (e.g., 80 percent of historical use), and a higher charge is set for consumption above the baseline. Rolling baseline rates can solve the problem of inclining block rates having a disproportionate effect on the larger customers in a class. We recommend that the Commission consider feebates and other rate designs over the next few years, but adopt the Facility Charges described above in test year 2011.

Q. IS IT POSSIBLE THAT PGE WILL SUFFER "REVENUE EROSION" DUE TO YOUR PROPOSAL?

A. In the short-run, yes; in the long-run, no. In our simple example for the City's water pumping loads, peak-period billing would allow the City to save about $36,500 annually in demand charges, some of which would otherwise presumably cover PGE's short-run fixed costs. With the higher tail-block Demand Charges, customer reactions could also cause underrecovery of fixed costs in the short-run. However, in the long-run, even greater amounts of new fixed (incremental) costs could be avoided or deferred if customers respond to these marginal price signals. Costs that are not incurred in the first place cannot lead to revenue erosion.

Q. ARE THERE MECHANISMS TO ADDRESS SHORT-RUN REVENUE EROSION ASSOCIATED WITH POLICIES INTENDED TO INCREASE EFFICIENCY?

A. Yes. These are referred to as "decoupling" mechanisms. If the recovery of PGE's fixed costs is threatened by the proposed change in rate design, a decoupling mechanism could address this problem.

Q. HAS THE COMMISSION APPROVED ANY "DECOUPLING" MECHANISMS IN THE PAST?

A. Yes. PGE already has Schedule 123, the Sales Normalization Adjustment. In this proceeding, we are only recommending that decoupling be tied to a new rate design, in addition to being tied to energy efficiency programs.

Q. DOES YOUR PROPOSAL ADDRESS ONE OF THE CONCERNS THAT PGE HAS RAISED ABOUT SCHEDULE 123?

A. We believe so. In Exhibit 1507 (Kuns-Cody/3), PGE has stated that "[t]he decoupling mechanism improves PGE's ability to recover its per customer fixed costs at forecasted levels approved by the Commission in its most recent rate case (UE-197); however, *Schedule 123 is not a full decoupling mechanism* in that the mechanism reflects only weather normalized sales and does not fully true-up fixed cost recovery because *large nonresidential customers are not decoupled*." (Emphases added.) We propose that the change in marginal demand charges be applied to Schedules 32, 83, 85 and 89, and that the decoupling mechanism be expanded to cover all these rate schedules. This should help address PGE's concerns about "full true-up" of fixed cost recovery. Schedule 123 provides a template for a "rate design decoupling" mechanism.

Q. DO YOU RECOMMEND ANY CHANGES TO SCHEDULE 123?

A. Yes. Schedule 123 provides for surcharges and rebates on a volumetric basis, which we understand are applicable to all energy charges in the relevant rate schedules. These surcharges and rebates should only apply to inframarginal energy charges, to preserve stability in the marginal charges.

Q. ARE THERE ANY OVERALL BENEFITS TO CUSTOMERS FROM DECOUPLING?

A. Yes. To the extent that recovery of PGE's legitimate fixed costs is ensured, PGE's cost of capital should fall. Investors should react by demanding a lower return on their investment (equity or bond), because of lower risk, and the utility should be able to rely to a greater extent on bonds than equity, also reducing the cost of capital. This should benefit all of PGE's customers. Also, to the extent that customers voluntarily take actions that conserve electricity, because of reductions in their energy bills, PGE's conservation programs can be retargeted, toward those who are unable to make changes (e.g., small businesses with limited access to capital markets for investments in energy efficiency) or are not well enough informed to make changes (e.g., commercial customers who do not have staff assigned to energy management).

Q. HAS DECOUPLING BEEN TIED TO INVERTED BLOCK RATES IN OTHER JURISDICTIONS?

A. Yes. The most recent example we have found is in Utah Docket 09-035-23, although the mechanism under debate in that docket applies only to residential rates. We see no reason to limit the mechanism to any one rate schedule, especially in light of PGE's concern about "full decoupling", and given that Schedule 123 already exists.

Q. DO YOU HAVE ANY OTHER PROPOSALS FOR SCHEDULE 32?

A. Yes. The proposed time-of-use structure for Schedule 32 is not based on cost causation principles. This TOU structure should be tied to the capacity and energy costs that PGE expects to incur, similar to what we have proposed regarding demand charges.

Q. SHOULD THE TIME-OF-USE ENERGY OPTION BE RETAINED FOR SCHEDULE 32?

A. Yes.

Q. DO ANY RATE SCHEDULES LACK A TIME-OF-USE OPTION?

A. Yes. Schedule 83 lacks this option, unlike Schedules 7, 32, 85, and 89. PGE should adopt a time-of-use energy charge option in Schedule 83.

Q. HOW SHOULD THAT OPTION BE DESIGNED?

A. The simplest approach would be to apply the methodology that PGE uses for Schedule 85: the "Projected Mid-C on/off peak delta" ($11.79/MWh on an annual average basis) provides a suitable basis for time-of-use charges in test year 2011. This annual average value should be replaced by monthly values, consistent with our testimony below on seasonality.

Q. ARE YOU AWARE OF ANY CONCERNS ABOUT "RATE TRANSITION"?

A. Yes. It would seem that one reason for the proposed declining block structure of Schedule 32 is that customers can "more easily" make the transition to Schedule 83. See, e.g., PGE/1500, Kuns-Cody/22-23. "Ease of transition" also motivates other charges. See PGE/1500, Kuns-Cody/24-25 and 27. However, incorrect price signals are a sufficient justification for modifying these schedules and adopting a different approach to "transition" between schedules.

Q. HOW WOULD YOU APPROACH THE ISSUE OF RATE TRANSITION?

A. First, we do not understand the policy objective in making it easier for customers to move "up" in the rate schedule structure, because that means they are using more electricity. However, it does seem reasonable that customers should understand the implications of moving from, say, Schedule 32 to Schedule 83. Instead of adopting an inefficient rate design for Schedule 32, PGE should provide information to those customers who are "on the cusp" of moving up to Schedule 83. Schedules 32 and 83 already contain conditions that require the customer to switch rate schedules: if a customer exceeds a threshold (has a "Demand Event") more than once during a 13 month period, the customer moves to the next higher rate schedule. The thresholds are 30 kW for Schedule 32 and 200 kW for Schedule 83.

Q. WHAT DO YOU PROPOSE INSTEAD?

A. Again, the objective is to encourage more efficient use of electricity via the rate structure, so we propose a change in the definition of Demand Events and a change in PGE's response to such Events. We propose retaining the 30 kW and 200 kW thresholds, but allowing a total of three Demand Events before the customer switches. This larger number of Events provides customers with more time to take actions that will keep them on the lower rate schedules, if that is their objective. Each Demand Event should trigger an automated notice to the customer. For example, the first Demand Event should trigger a simple notice that the customer has crossed the Demand threshold, and that there is a risk that the customer will be switched to a higher rate schedule; the notice would point to the location on PGE's web site where the new rate schedule could be found. The second Demand Event should remind the customer again, but also include a calculation of the customer's bill under the higher rate schedule, so that the customer would have more information about the possible change in energy cost. The third Demand Event should contain a "final notice", in addition to the above information. The fourth Demand Event would trigger the transition to the higher rate schedule. We realize that this would require changes in PGE's billing system.

Q. DO YOU PROPOSE ANY OTHER CHANGES IN RATE DESIGN?

A. Yes. PGE's rate structures have no seasonality: the demand and energy charges are the same in all months. This does not reflect expected spot market prices in test year 2011, which have a distinct seasonality. *See* Exhibit COP/107. Customers should know that their consumption in different months has different implications for system energy costs. In test year 2011, the flat energy charges in Schedules, other than Schedule 7, should be replaced with revenue-neutral seasonally-shaped energy charges, using the shape of PGE's forecast of Mid-C spot prices. Schedule 7 should be excluded from this change because of the concern about residential customers who rely on electricity during the winter for health and safety. Other approaches to efficiency are more likely to be effective for residential customers. In future years, the Commission should consider seasonally shaped demand charges as well, especially given that PGE projects the need to acquire capacity (generation and transmission) to meet peak loads in "only" four months of the year.

III. Schedule 91

Q. WHAT ARE YOUR CONCERNS ABOUT SCHEDULE 91?

A. We have three concerns. First, the City has encountered billing difficulties when experimenting with new lighting technologies, due to limitations on the number of "lamp codes". Second, the City has long been charged for streetlight circuits that are located outside the City and used solely by other Schedule 91 customers. Third, PGE's proposed charges for emergency maintenance do not reflect the provisions in Schedule 91 that permit PGE to charge the customer for complete replacement instead of repair.

Q. WHY IS THE CITY EXPERIMENTING WITH NEW LIGHTING TECHNOLOGIES?

A. The City wants to save energy and reduce costs, consistent with the City's long-standing commitment to energy conservation and sustainability. For example, in a recent test, new LED luminaires used less than half of the energy consumed by the HPS fixtures they replaced. Further, new technologies such as the LED and QL lamps have significantly longer lifespans, thus reducing maintenance costs, reducing outages and possibly increasing public safety. New technologies are not limited to entirely new lamps, but include the possible addition of devices that will allow some lamps to be turned down or off at night.

Q. WHAT ARE LAMP CODES?

A. Because streetlights are an unmetered load, Schedule 91 customers are billed based on the installed number of specific lamp types, an assumption about the number of hours per year that each lamp is operating, and the power consumption of each luminaire. The combination of this information yields an assumed level of energy consumption per lamp type per month. Each lamp type is assigned a code for billing purposes which incorporates this information. The City maintains an inventory of its lamps and reports that to PGE periodically. The City's bill reflects the number of lamps by code, as well as other information.

Q. DOES PGE'S BILLING SYSTEM HAVE LIMITATIONS ON THE NUMBER OF LAMP CODES?

A. Yes. Lamp codes are limited to two digits, which means that at most 99 codes are available within the billing system. The effect of this limitation is that new lamps are sometimes assigned to the wrong code, which leads to inaccuracies in the billing process.

Q. CAN THE PROBLEM BE SOLVED WITHOUT CHANGING THE NUMBER OF LAMP CODES?

A. In the short run, we believe that there are several solutions. In the long run, however, it is probably necessary to expand the number of lamp codes, either by moving to three digits or using an alphanumeric method.

Q. WHAT ARE SOME SHORT-RUN SOLUTIONS?

A. First, a number of lamp codes are currently "unassigned". These should be assigned to specific new lamp types and to dimmable lamps on an as-requested basis. Second, we understand that some lamp codes may be "retired" over time, as technologies become obsolete and are replaced. PGE should set up a process to "retire" codes, which should also be made available for new technologies. Third, Schedule 91 customers should be permitted to "self-report" Option C lamps, which are owned and maintained by the customer, using a process analogous to that already in place for Schedule 92 (signals):

customers would inform PGE of locations, wattage, energy consumption, and technical specifications of Option C lamps. Because some lamp codes only apply to Option C lamps, this would free up additional codes for experimentation and innovation.

Q. SHOULD PGE PLAN ON A LONG-TERM SOLUTION?

A. Yes. As PGE updates its billing systems, provision should be made for either three digit or alphanumeric lamp codes.

Q. PLEASE DESCRIBE YOUR CONCERN ABOUT CIRCUITS.

A. The City believes that it is being overcharged for streetlight circuits, because of the difference between (a) the share of total circuit *costs* paid by the City and (b) the share of total *circuits* (measured by either circuit-miles or circuit counts) inside the City. This difference arises because (a) in the cost allocation process all Option B lamps are assigned a dedicated circuit, which is incorrect, and (b) the City has an above-average number of Option B lamps that do *not* require a dedicated circuit.

Q. WHAT EVIDENCE SUPPORTS THIS BELIEF?

A. In response to discovery, PGE has provided the total number of circuits and the total mileage of such circuits, both inside and outside the City. From a recent billing from PGE, the City has calculated the share of total circuit costs paid by the City: about 32 percent. (As of February 2010, the City had 43,936 Option B lights. Under proposed Schedule 91, 43,936 * $1.38/mo. * 12 mo. = $727,580. PGE's total circuit charge costs (revenues) for test year 2011 are projected to be $2,295,034.[1] Therefore, the City is paying 31.7 percent of PGE's total circuit costs.) This share of total costs paid by the

[1] This projected number is found in PGE's workpapers. *See*, Stl_RateSpread_2011_final_wkp.xls, tab "wp-page7-10", cell E110.

City is substantially higher than the share of circuits, measured either by circuit count or circuit miles. The data on circuit counts and circuit miles is provided under separate cover, because PGE designated this information as "Confidential" (as Attachment COP-016B, in response to the City's request COP-016). *See*, Exhibit COP/108 (CONFIDENTIAL).

Q. HOW ARE THESE ASSETS DIFFERENT FROM, SAY, SUBSTATIONS OR TRANSMISSION LINES?

A. Streetlight circuits are "at the end of the line". These are not shared facilities, which would require the development of some kind of cost allocator. The City uses only those circuits that are inside the City; other Schedule 91 customers use only circuits that are outside the City.

Q. HOW SHOULD THIS PROBLEM BE SOLVED?

A. The simplest approach would be a billing adjustment. First, PGE's billing system would continue to charge all Option B lights for all Schedule 91 customers as if these lights are all responsible for these costs. Second, the City would receive a credit on its bill equal to the difference between (a) the share of total monthly circuit costs paid by the City in the first step and (b) the share of total monthly circuit costs represented by the "City's share of circuits". In turn, the City's share of circuits would be calculated by simply averaging the shares of circuit miles and circuit counts, as reported by PGE for 2009. The credit to the City would be recovered by PGE from other Schedule 91 customers in whatever manner PGE and the Commission determine to be suitable.

Q. WHY IS THIS AN EQUITABLE SOLUTION?

A. As noted above, the City has been paying for facilities that are outside the City, and from which the City derives no benefit. With this billing adjustment, those customers with dedicated circuits will pay for them in proportion to their actual use. In addition, the City's share of total circuit miles and circuit counts has fallen in the last few years, based on the confidential information received from PGE. This makes sense, because of growth in suburban areas. The effective subsidy by the City of other Schedule 91 customers has been growing, and should be eliminated.

Q. WHAT ARE YOUR CONCERNS ABOUT STREETLIGHT MAINTENANCE COSTS?

A. Schedule 91 (Sheet No. 91-3, emphases added) places limits on PGE's obligation to perform emergency maintenance:

> <u>Emergency Lamp Replacement and Luminaire Repair</u>
> The Company will repair or replace damaged luminaires that have been deemed inoperable due to the acts of vandalism, damage claim incidences and storm related events that cause a luminaire to become inoperable. Without obligation or notice to the Customer, individual lamps will be replaced on burnout *as soon as reasonably possible* subject to the Company's operating schedules and requirements. Non-operating luminaires will be repaired by the Company without additional charge to the Customer *only when* the luminaire can be restored to operable status by repair or replacement of certain failed parts including the lamp, power door (if applicable), photoelectric controller, starter and lens. If repair efforts by the Company do not result in an operable luminaire, *the luminaire will be designated as non-repairable and replaced, the cost of such replacement is the responsibility of the Customer.*

PGE's obligation is (a) limited in time ("as soon as reasonably possible"), and (b) in kind ("only when the luminaire can be restored to operable status by repair or replacement of certain failed parts"). Furthermore, PGE retains the ability (c) to designate the luminaire as "non-repairable", in which case the replacement cost falls on the customer.

Q. DO YOU OBJECT TO THESE LIMITATIONS?

A. Not entirely. We are not in a position to second-guess or micromanage PGE's dispatch of repair crews in emergency situations. However, the second and third limitations provide PGE the opportunity to make unilateral determinations that cause individual customers to bear full replacement costs, rather than standard maintenance fees, without any opportunity for the customer to challenge PGE's decisions. We are concerned that PGE may "lean" toward making decisions that shift costs to the customer in emergency situations, thus shifting the entire risk of replacement in an "emergency" to customers from PGE. We do not advocate giving the customer the right to challenge PGE's decisions in emergency situations. However, in compensation for taking on the risk of replacement instead of repair, customers should receive the benefit of the least-cost assumption for the dispatch of crews for emergency service.

Q. WHAT DOES PGE ASSUME FOR CREW DISPATCH?

A. In the streetlight maintenance cost study, PGE assumes various combinations of three crew types are dispatch for emergency repairs: Lamp Replacer, Eagle, and Line Crew. Eagle is the least expensive, and Line Crew is the most expensive. The streetlight maintenance study does not provide any documentation for the source of the assumptions for crew dispatch, or for many of the inputs to the marginal costs of maintenance. Because marginal costs are overstated, we conclude that budgets are likely overstated, if they are driven by the same underlying assumptions about crew dispatch. (If the budgets are driven by different assumptions about crew dispatch, then there is a disconnect between the marginal cost study and the projected budgets.) Because of the lack of documentation in general, and the ability to shift replacement risk to the customer, PGE's proposed streetlight maintenance budget should be reduced by the savings implicit in dispatching Eagle crews, which are the least cost, for emergency repairs (except luminaire replacement), instead of the mixed crew dispatch assumed in the initial filing. (We do not propose changing PGE's assumption about crew dispatch for luminaire replacement, because this appears reasonable.) This would reduce the proposed maintenance budget by $215,000, or eight percent.

IV. Customer Impact Offset

Q. WHAT DOES PGE PROPOSE REGARDING THE CUSTOMER IMPACT OFFSET (CIO)?

A. PGE proposes four constraints on rate changes by customer class, including a cap of 1.25 times the average rate increase for eight rate schedules, a cap of 2.00 times the average increase for four other rate schedules, a cap on the CIO credit of 95 mills/kWh, and a floor that ensures no rate schedule receives a decrease due to the CIO. The result is that costs are moved from Schedules 38, 47, 49, 83 and 93 to Schedules 15, 85, 89, 91, and 92. PGE's testimony does not offer any Commission ruling supporting this specific CIO design. PGE/1500/Kuns-Cody.

Q. WHAT HAS THE COMMISSION RECENTLY SAID ABOUT CIO?

A. In Order 01-777 (pp. 37-38), the Commission stated that "[i]n the past, this Commission has phased out the customer impact offset and similar offsets in conjunction with other general rate changes. We affirm that practice, which allows us the opportunity to consider the impact of rate changes on all customer classes at the time that general rates are being changed." In Order No. 07-015, the Commission adopted the following stipulation on CIO: "the Customer Impact Offset (CIO) will be limited to a 2.0 times overall average rate increase percentage to all schedules. No CIO credit to mitigate rate impact will exceed 3.5 cents/kWh, and a CIO credit will not be applied to rate schedules with a rate increase of less than five percent."

Q. WHAT DO YOU RECOMMEND?

A. The City recommends that the Commission consider eliminating the CIO in this docket. The total dollars shifted due to the CIO is about $14 million in a total revenue requirement of about $1.8 billion, or less than one percent. Furthermore, the CIO interferes with broader public policy goals, as articulated above.

V. Summary

Q. PLEASE SUMMARIZE BRIEFLY YOUR PROPOSALS.

A. We recommend the following changes:

1. Reverse the proposed assignment of Service and Transformer costs to the Customer Charge category.
2. Set the total tail-block Demand Charges at about $7.00-8.00/kW.
3. Add a time-of-use option to Schedule 83, modeled on Schedule 85.
4. Change the billing determinant for all demand charges in all rate schedules to the customer's peak load during the Peak Period only.
5. Reduce inframarginal Facility Charges to achieve revenue neutrality on an expected basis in each rate schedule.
6. Expand Schedule 123 to address the potential for underrecovery of fixed costs from volumetric charges due to these changes in rate design.
7. Provide specific information to customers who are "in transition" from one rate schedule to another.
8. Add a seasonal shape to all energy charges.

9. Adopt specific short-run solutions to the problem of limitations on lamp codes, while preparing for a long-term expansion of codes.
10. Credit the City of Portland so that the City pays for its actual share of streetlight circuits.
11. Consider eliminating the CIO.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Qualification Statement of Richard Gray

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

A. My name is Richard Gray. I am currently employed as a Contract Administrator and Senior Management Analyst with the Bureau of Transportation for the City of Portland ("PBOT"). My business address is 1120 S.W. 5th Avenue, Room 800, Portland, Oregon 97204.

Q. PLEASE STATE YOUR EDUCATIONAL QUALIFICATIONS.

A. I have a Bachelor's Degree in Political Science from the University of Oregon and a Master's Degree in Public Affairs from the University of Oregon.

Q. PLEASE REVIEW YOUR EXPERIENCE IN THE ELECTRIC UTILITY INDUSTRY.

A. In my current capacity I assist in managing the administration of contracts for PBOT. This includes ensuring compliance with laws and policies and outreach to the minority contracting community. I also perform several other functions that are not directly related to contract administration, including legislative analysis and liaison, utility pole attachment policies and practices, and street lighting rates and finances. Prior to my current position, I performed various management and analytical tasks for PBOT. For ten years, I was the City's Street Lighting Manager. I also serve as a Board Member in the Oregon Joint Use Association, which is a utility group with statutory authority to advise the Commission on utility pole joint use issues.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I testified in Docket UE 115, provided comments in AR 506, and filed testimony in UE 179 and UE 180.

Q. DOES THIS COMPLETE YOUR QUALIFICATION STATEMENT?

A. Yes.

Qualification Statement of Peter Koonce

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

A. My name is Peter Koonce. I am currently employed as the Division Manager for Signals, Street Lighting, and ITS within the Bureau of Transportation for the City of Portland ("PBOT"). My business address is 1120 S.W. 5th Avenue, Room 800, Portland, Oregon 97204.

Q. PLEASE STATE YOUR EDUCATIONAL QUALIFICATIONS.

A. I have a Bachelor's of Science Degree in Civil Engineering from Oregon State University and a Master's of Science Degree in Civil Engineering from Texas A&M University.

Q. PLEASE STATE YOUR ACADEMIC EXPERIENCE.

A. Between 1993 and 1995, I was a Teaching Assistant at Oregon State University. From 2002 to the present, I am an Adjunct Professor at Portland State University. I have served as a guest lecturer at the University of Portland on many occasions. I have also published and presented various papers in the fields of transportation.

Q. PLEASE REVIEW YOUR EXPERIENCE IN THE ELECTRIC UTILITY INDUSTRY.

A. In 1995, I joined Kittelson & Associates, Inc. as a transportation analyst and was involved in design of traffic signals and street lighting systems. In this capacity, I worked on installation of new intersections and modification of existing systems. I supervised engineers in the development of plans for jurisdictions throughout the Pacific Northwest as well as east coast clients.

In my current capacity, I manage the Signals, Street Lighting, & Intelligent Transportation Systems Division for PBOT. This role includes ensuring compliance with laws and policies of the State of Oregon and the City of Portland. My experience with the electric utility industry is limited to interaction and coordination on traffic signal, street lighting, and Intelligent Transportation System (ITS) projects.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. No.

Q. DOES THIS COMPLETE YOUR QUALIFICATION STATEMENT?

A. Yes.

Qualification Statement of Peter Nierengarten

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

A. My name is Peter Nierengarten. I am currently employed as an Engineer with the Portland Water Bureau (PWB). My business address is 1120 S.W. 5th Avenue, Room 600, Portland, Oregon 97204.

Q. PLEASE STATE YOUR EDUCATIONAL QUALIFICATIONS.

A. I have a Bachelor's and a Master's Degree in Civil Engineering from the University of Arkansas.

Q. PLEASE REVIEW YOUR EXPERIENCE IN THE ELECTRIC UTILITY INDUSTRY.

A. In my current capacity I lead energy management at the PWB. My duties include tracking and documentiaton of Water Bureau facility energy consumption, developing and supporting energy/cost savings project and initiatives, and championing the development of alternative/green energy projects. I also regularly interact with Portland General Electric to determine how various projects or operational changes may impact our energy consumption, demand charges and resulting bills. Additionally, during 2009 I lead the Water Bureau's participation with the Energy Trust of Oregon's pilot Industrial Efficiency Improvement program.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. No

Q. DOES THIS COMPLETE YOUR QUALIFICATION STATEMENT?

A. Yes.

Qualification Statement of Lon L. Peters

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

A. My name is Lon L. Peters. I am the President of Northwest Economic Research, Inc. My business address is 607 S.E. Manchester Place, Portland, Oregon 97202.

Q. PLEASE STATE YOUR EDUCATIONAL QUALIFICATIONS.

A. I received the Bachelor of Arts degree in economics from Reed College in 1974, and was elected to Phi Beta Kappa. I received the Master of Arts, Master of Philosophy, and Doctor of Philosophy degrees, also in economics, from Yale University in 1976, 1978, and 1981, respectively.

Q. PLEASE STATE YOUR ACADEMIC EXPERIENCE.

A. Between 1976 and 1979, I was a Graduate Research Assistant and Teaching Fellow at Yale University. From 1979 to 1980, I was a Guest Scholar at The Brookings Institution in Washington, D.C., and was Lecturer, then Assistant Professor of Economics, at Goucher College, in Towson, Maryland. I was Visiting Assistant Professor (1980-82) and Visiting Professor (2007-09) of Economics at Reed College, where I taught microeconomic theory (introductory and intermediate/advanced), energy economics, the economics of industrial organization, and economic history. In the winter of 1984, I was a guest lecturer at the School of Public Administration, at Lewis and Clark College in Portland. From 1991 to 1996, I was the Chair or Co-Chair of the Economics Section of the Oregon Academy of Science. I have also published and presented various papers in the fields of energy economics and economic history.

Q. PLEASE REVIEW YOUR EXPERIENCE IN THE ELECTRIC UTILITY INDUSTRY.

A. In 1982 I joined the Division of Rates at the Bonneville Power Administration, and subsequently was appointed Chief of the Wholesale Rate Section. While at BPA I worked on forecasts of wholesale and retail rates in the Pacific Northwest, and on BPA's long-run incremental cost of service. I also supervised the development of BPA's Wholesale Power Rate Design Study for the 1985 rate case, and assisted in the development of BPA's testimony for the hearings before the Federal Energy Regulatory Commission (FERC) concerning BPA's 1981, 1982, and 1983 nonfirm energy rate schedules.

In 1986 I joined the Public Power Council (PPC) as Senior Economist, where I worked on most aspects of the relationship between BPA and its consumer-owned utility customers in the Northwest: wholesale rates, regional and extra-regional marketing, revenue requirements, resources, contracts, fish and wildlife economics, federal and state regulations, and load forecasting. While at PPC, I served on technical review panels at BPA, the Pacific Northwest Utilities Conference Committee, the Northwest Power Planning Council, and the National Marine Fisheries Service.

In late 1994, I opened the Portland office of R.W. Beck, a national economics and engineering consulting firm. Until late 1995, I served as Director of the Portland Office and as Executive Economist. My practice included advising a variety of public power clients across the country on issues of wholesale power supply, including the solicitation and analysis of proposed power supplies, retail contracts and rate design, power and transmission contract negotiation and renegotiation, transmission access and pricing, and unbundled wholesale power rate design.

Since early 1996, I have provided independent economic consulting services to a variety of clients in the Northwest, California, and the rest of the United States.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS?

A. Yes. I testified on behalf of BPA before Federal Energy Regulatory Commission (FERC), on behalf of various clients in BPA's rate proceedings (power and transmission) since 1987, before state regulatory commissions in Idaho, Oregon and Washington, and before the FERC.

On behalf of the City of Glendale, California, I testified before the Oregon Public Utility Commission (OPUC) regarding the auction of generation and contract assets by Portland General Electric.

On behalf of the Metropolitan Water District of Southern California, I testified before the California State Assembly on the subject of wholesale water wheeling in the State of California.

On behalf of the Cities of Burbank, Glendale, and Pasadena, California, I testified before the Department of Energy Board of Contract Appeals regarding financial damages sustained under long-term power purchase agreements.

On behalf the Public Generating Pool, Tacoma Power, and the Washington Public Utility Districts Association, I delivered testimony before the Northwest Energy Caucus of the U.S. Congress, on the subject of proposals for restructuring of the Northwest transmission system.

On behalf of REBOUND, I prepared reports on regional energy market conditions and testified before the Idaho Department of Water Resources regarding the application for water rights by Cogentrix, Inc. and Newport Northwest.

On behalf of the City of Portland, I testified before the Oregon Public Utility Commission in Dockets UE 115, UE 116 and UE 180, regarding unbundled rates, marginal cost rate design, tariff provisions, credits for demand reductions and small power generation.

On behalf of the City of Hermiston, Oregon, I prepared a report on "Private Costs and Public Benefits Associated with the Condemnation of Electric Utility Distribution Facilities by the City of Hermiston, Oregon", and testified at trial before the Circuit Court of the State of Oregon for the County of Umatilla.

On behalf of Emerald People's Utility District, Eugene, Oregon, I prepared a report on "Potential Private Injury Aspects of the Transfer of Service Territory to the Emerald People's Utility District", and testified at trial before the Circuit Court of the State of Oregon for the County of Linn.

On behalf of the City of Glendale, California, I filed an affidavit at the Federal Energy Regulatory Commission regarding damages under pricing provisions of a long-term power sale and exchange agreement in Docket No. EL06-5-000; this affidavit was also filed before the U.S. District Court for the District of Oregon, Case 3:05-cv-01321-PK, in support of a motion to dismiss.

On behalf of the Cities of Tacoma and Seattle, Washington, I filed a declaration before the Superior Court of the State of Washington in and for the County of Spokane, No. 05201697-8, regarding the interpretation and application of the term "prudent utility practices" to retail rate-setting by municipal utilities, and submitted a report regarding damages to a mediator designated under a power purchase agreement.

On behalf of Turbine Technology Services, Inc., I testified before an arbitrator appointed by the Supreme Court for the County of Niagara, State of New York, in Case No. 110482, regarding damages associated with generation plant capacity and general determinants of the value of assets in power markets, in litigation related to an outage of a power generation plant in upstate New York.

Q. DOES THIS COMPLETE YOUR QUALIFICATION STATEMENT?

A. Yes.

Inframarginal and Marginal Charges

Energy (mills/kWh)

Schedule	Block 1	Block 2	Block 3
7	94.92	112.35	119.92
32	102.56	75.32	
47	128.14	108.14	
83	67.93		
85-S	69.39		
89-S	67.51		

Capacity ($/kW-mo.)

Schedule	Block 1	Block 2	Block 3
7	n.a.		
32	n.a.		
47	n.a.		
83	$5.71	$5.21	
85-S	$4.87	$4.87	
89-S	$4.70	$4.70	$3.31

Sch. 85 and 89: Secondary voltage and Peak prices only

Draft PGE Scoping Plan for AMI Benefits

I. Introduction

In PGE's most recent general rate case, OPUC Docket No. UE 180 (see PGE Exhibits 800, 2300, and 3000), PGE submitted a proposal for an advanced metering infrastructure (AMI) system. As we explained in the March 2006 filing that initiated that docket: "PGE believes now is the appropriate time to launch an AMI project because the technology is mature and a number of parties have signaled their interest in moving forward with future methods of grid management and demand response. We cannot begin to achieve these goals without AMI." PGE Exhibit 800 at 3. These reasons are even more compelling now. Since March 2006, initial results from our current Integrated Resource Planning (IRP) process indicate that PGE will need to acquire approximately 900 MW of capacity by 2012. Demand-side resource can and should play a significant role in filling this need. Demand-side programs not only help ease pressure on PGE's electric delivery system during peak load times and reduce the risk of interruptions during extreme peaks but, importantly, participating customers reduce their electric bills and save money. No other resource can save customers money as we deploy it. PGE is very interested in demand-side benefits and we are confident that the AMI system we propose will support them. We do not expect implementing demand-side programs to require complicated connections with the information platform because, from 2000 through 2003, PGE had already developed much of the IT software and system integration needed to operate a fully functioning AMI system.

As we began this project in 2005, we initially focused on the operational effects and benefits of changing how we meter customers' usage. We needed to manage the change well, and sound business practices required that we identify and capture what benefits we could as we made the necessary process changes. Pursuant to Staff's requests (in Staff Exhibit 700), we have started and/or completed implementation plans for those changes and benefits that stem from the change in technology. With this document, we add to it our scoping plans for achieving the customer- and system-related benefits that moving to metering grounded in two-way, real-time communication – rather than a monthly manual read – will enable. These fall into the categories of:

- Demand response programs.
- Information-driven energy savings.
- Improved distribution asset utilization.
- Improved outage management.

In 2007, we will develop implementation plans for these benefit categories.

Using the current system cost estimate of approximately $132.2 million, we anticipate $18.2 million in annual cost savings from operational benefits in 2011, after the system is fully deployed. These costs and benefits produce a net present value benefit of approximately $34 million over 20 years of system operation. With the benefits identified in this scoping plan, we estimate that the net present value benefit of deploying AMI now could increase to between $37 million to $80 million (see Attachment 1) depending on customer acceptance of demand-response initiatives and various other necessary assumptions.

II. Regulatory Status

Based on comments from the OPUC Staff and other parties, PGE agreed to remove AMI from UE 180 with the understanding that we would resubmit the proposal in a separate, non-rate case proceeding. This filing will encompass the accelerated depreciation of non-AMI meters and other NMR infrastructure that is no longer needed by the new system, plus the revenue requirement of the new AMI system less O&M savings throughout the deployment period.

To support this application, PGE agreed to submit the following documentation:

- A detailed implementation plan for the O&M benefits that PGE reasonably expects to achieve as we implement this technology change.
- A scoping plan for customer- and system-related benefits not covered in PGE's original financial analysis. Our proposed AMI system enables or supports these benefits , but most require additional costs or investment .

PGE is submitting the detailed implementation plan for primary benefits in conformance with the description provided in UE 180, Staff Exhibit 700. The scoping plan below includes the following information:

- The benefit categories that PGE will pursue based upon highest perceived benefit versus cost.
- A timetable for implementation plans.
- A range of potential benefits for the specified programs.

During 2007, PGE will develop implementation plans for the specified benefit categories of this scoping plan.

III. Customer- and System-Related Benefits

In accordance with PGE Exhibit 3000 (OPUC Docket UE 180), PGE submits this scoping plan to support its proposal for an AMI system. This scoping plan addresses the following broadly defined AMI benefit categories:

- Demand response initiatives
- Energy savings prompted by the availability of hourly usage data
- Improved distribution planning
- Improved outage management

Estimating the net benefits of these initiatives is more challenging than with the operational changes because most require additional investment or cost and some entail customer acceptance as a key variable. Where possible, we drew on industry standards and experience, but this is limited and requires that we consider differences among utilities in general. The accompanying spreadsheet documents the calculations for the more complicated estimates. We have provided ranges estimates because, as noted below, typically the most sensitive variables that determine the benefit value depend on either data not yet collected at PGE or on customer acceptance of new programs. Also provided below are the basic assumptions PGE used to estimate the net benefits for specific sub-category initiatives. These subcategories will be the focus for subsequent implementation plans.

Demand Response

PGE has a strong interest in demand response. A successful demand response program would further the company objectives of reducing generation supply costs and increase options for customers to control their monthly electricity bills. Because PGE needs to acquire, approximately 900 MW of capacity, as identified during IRP planning, we fully recognize demand response as a potential means to supply some of this peak capacity. In addition, AMI-supported demand response programs would be an invaluable resource during the next possible "energy crisis." Many regulators and utilities undoubtedly wished that AMI systems had been in place during the energy crisis of 2001-2002. While a subsequent energy crisis is currently unforeseen and would undoubtedly occur for different reasons, the possibility exists and could occur both rapidly and unexpectedly. If so, AMI systems, and demand response programs in particular, could either help mitigate the effects or be wished for yet again.

Outside of PGE there is a considerable interest in demand response from federal departments and many state regulators. However, as discussed in most regulatory and industry trade meetings on this subject, there is considerable uncertainty in the possible outcomes from program implementation. Typical topics for debate include:

- What is the likely interest among customers?
- How do we encourage high levels of participation?
- What amount of demand shift will customers provide?
- What is the best way to design rates?
- How should we value the benefits of the demand that is shifted?

What are no longer discussed are the requirements for an AMI system to support these programs. PGE's proposed AMI system will provide robust support for future program design.

PGE has been fully engaged in a number of these regulatory and industry forums, in some cases providing leadership for defining the necessary changes. Two overarching conclusions can be drawn from these meetings and these pertain to PGE also.

1. For demand response to be successful, the industry needs to gain experience in implementing, promoting, operating, and evaluating these programs.
2. To participate in a meaningful way, most customers will need major appliances that respond automatically and effectively by receiving utility control and/or price signals directly.

Based on these conclusions, PGE's near term actions will be to develop implementation plans to address the two needs. The first effort will be a plan for a demand response market pilot, and the second, a plan for a market transformation initiative based on the lessons learned from PGE's participation in the NW Grid-Friendly Appliance (GFA) project. While these plans look feasible, cost effectiveness depends – as is always the case – on assumptions that future conditions may cause to change.

Demand Response Market Pilot

At present, we plan an Opt-In, Critical Peak Pricing (CPP) Tariff Pilot for 2009 implementation, targeted at residential customers, with one-time development costs of approximately $1 million in 2008 and 2009. After launching in 2009, our effort would be to reach the maximum participation rate by 2013, with a total of twenty critical-peak price events during the winter and summer. By 2013, we would evaluate and engage in any necessary program re-design to maintain the acceptance rate.

Attachment 2 to this document provides a simple model that includes most of the costs of the program. The model is simple so as to emphasize the sensitivity to three variables that correspond to the chief uncertainties: the number of customers that participate, the average kW load shift per customer, and the value of capacity.

To explore the range of possible benefits, we created a nominal scenario, a low scenario and a high scenario. The range of net present values for the three scenarios varies between a negative value and $27 million dollars. The duration of the program is coincident with the life of the AMI system. Note that $27 million occurs in the high scenario with an assumption of only 10% market penetration. We used this assumption because few opt-in programs at PGE have participation as high as 10%. Changes in societal energy interests, however, could drive a much higher acceptance rate and the benefits would increase accordingly. The following variables represent the primary assumptions used in Attachment 2:

Customer Participation
The single biggest uncertainty is customer participation rate. In the nominal case, we assume participation reaches 5% (about 40,000 customers.) In the low case we assume 1.5% acceptance and 10% in the high case. The specific elements of the rate design (and its associated terms), customer education efforts, and how effectively the offer is promoted will likely significantly affect program acceptance. A break-even result requires the fairly large participation of the Low Scenario because of the one-time startup cost of approximately $1 million

Load Shift
The nominal average value of 0.5 KW shifted per customer is based on PGE's Analysis of the Load Impacts and Economic Benefits of the Residential TOU Rate Option section on CPP. Because this estimate is not based on experience in PGE's service territory, actual results could vary considerably. The Low Scenario assumes 75% of this value and the High Scenario 140%.

Avoided Capacity Cost
The primary benefit driver is the cost of avoided capacity. Again, with almost no industry experience with CPP programs the appropriate value to associate with capacity is difficult to estimate. One alternative is the annual cost associated with a simple cycle combustion turbine (CT). In PGE's IRP, this value is more than $70/kW per year. We believe this avoided cost may

be high, however, for two reasons. First, at least in the recent past, PGE has found capacity resources that cost less than this. Second, there are no restrictions on how many hours a CT provides capacity and a CT provides reactive current support to the transmission grid during peak periods. Gauging from this avoided cost, we used a value of $29 per KW-year in the Low Scenario because this is what we have incurred, to date, to implement resources for PGE's distributed generation program. In the Nominal Scenario we assume a value of $36 per KW-year and $58 in the High Scenario.[1]

Appliance Market Transformation[2]

The residential sector accounts for approximately 25% of PGE's winter system peak demand, from a combination of water/space heating, cooking, refrigeration and lights. Hourly price signals sent to customers might motivate a substantial shifting of this load to less expensive off-peak hours without significant inconvenience to customers, particularly if the decision how and when to participate could be made just once in appliance set-up. Three market barriers presently exist. First, customers are frequently not at home to manage the load when the price signal is sent. Second, the cost to operate individual appliances (much less the knowledge and the ability to change how the appliance operates) is not well understood by customers. Third, electricity is a low involvement product; most consumers of electricity rarely think about it and tend to take it for granted. The solution to this problem is to have appliance manufacturers modify their appliances to (1) "hear" price and/or control signals from the utility, and (2) include a simple control at the appliance so the customer can make a one-time decision about how much of the appliance function they are willing to give up when the price of electricity is high. Having put those elements into place, the actual load shifting would be an automated function triggered by utility price signals. This is the "smart appliance" concept.

Our plan is to define a technology trial for either water heaters or thermostats whereby a consortium consisting of PGE, our AMI vendor, an appliance or thermostat manufacturer, and other interested parties[3] develop a project to create a 10 MW demand response resource by decreasing the installed cost per kW through an appliance market-transformation approach. As suggested above, the components of a smart appliance demand response system include (a) a communications-ready appliance, (b) a communications device[4], and (c) a communications method between the customer (or appliance) and the utility (e.g., AMI network).

In the end state of appliance market transformation, the incremental cost to develop a communication-ready appliance is expected to be about $2 to $5 per appliance.[5] When sufficient

[1] These avoided cost values are for illustrative purposes and not intended to be indicative of PGE's avoided cost under the Public Utility Regulatory Policies Act.
[2] While the examples that follow focus on price responsive programs, PGE intends to review direct load control opportunities in our implementation plan for demand response as well. Direct load control will also be addressed in PGE's IRP.
[3] E.g. Pacific Northwest National Lab, Bonneville Power Administration, Oregon Department of Energy (ODOE), Northwest Power Planning Council, US DOE, etc.
[4] This would be an after-market, low-cost communication device that would pass price and/or load control signals after plugging the device into the appliance, much like inserting a WiFi device into a computer USB socket.
[5] For the technology trial described here, the estimated cost to get these appliances into the home is almost $100 per water heater. This is because no communication-ready standard for appliances exists today. In addition to a higher appliance cost, marketing costs must be incurred to get the appliances into the home.

numbers of such appliances exist, the utility can implement a very cost-effective program simply by mailing communication devices to those customers who choose to participate. Also in the end state, we estimate the communication device to cost between $0 and $20 depending on what communication resources already exist in the home. (At the lower volume of the demonstration, a $40 cost is expected.)

The main objectives of the technology trial are to:

- Prove the concept of a communication-ready appliance to further the goal of a national standard in this area
- Demonstrate a program where control implementation is achieved by providing only communication devices after sufficient appliances are available to warrant the launch of the program.
- Create a technology-assisted, 10 MW demand response capability.
- Demonstrate that the installed cost per controllable kW is greatly reduced through market transformation.

The milestones in this project are to:

- Make available from the usual retail sources new, communication-ready thermostats or water heaters for use in new construction and replacement applications.
- Promote the selection of these appliances through standard program techniques.
- Promote and install a communication device (one most likely compatible with the AMI system) to allow the customer to capture automated-control benefits and reduce their energy costs under a time-of-use (TOU) or critical peak pricing (CPP) tariff. This will occur in the second or third year of marketing the program,

PGE's specific implementation plan for this initiative, which we will submit in 2007, will describe the following actions:

- Detail the costs, benefits, and timeline to implement the project outlined above.
- Explore membership interest in a consortium to demonstrate the smart appliance concept.
- Form the consortium if possible; otherwise, state barriers to formation.

Example Benefit/Cost Analysis[6]

We assume on-peak contribution of water heaters to be 0.85kW. To create a 10 MW resource, PGE customers must purchase approximately 15,000 "smart appliance" water heaters. We also assume 5,000 water heaters are sold in each of three (3) years—3,500 in the replacement market and 1,500 in new construction. An appliance manufacturer will need to contribute non-recurring engineering cost to the project. PGE will pay for incremental hardware cost at the appliance for an estimated $15 per water heater. PGE's marketing cost per water heater is estimated to be $60. In the second or third year, PGE would promote a direct load control and/or a TOU program to the customers owning these water heaters. To achieve an 80% participation rate, PGE might guarantee an annual bill savings to each customer. This amount, however, should have a near

[6] This example is for a communication-ready water heater; a thermostat trial would have very different results.

zero fulfillment cost, due to energy usage shifted away from on-peak. We estimate the customer-installable communication device to be approximately $40 apiece and other one-time program costs to be approximately $250,000. Consequently, we estimate the total installed capital cost to be approximately $1.6[7] million for a 10 MW resource or approximately $160/kW.

Without regard to the considerable societal benefits in this demonstration, PGE's annual net benefit on this 10 MW resource, compared to a supply side resource for capacity, varies between zero and $460,000 depending on the actual implementation costs and avoided capacity cost assumed. The details of this calculation are shown in Attached 2.

Information-Driven Energy Savings

PGE plans to conduct primary research on how to provide customers useful information from interval data. We also intend to develop an information tool based on the results of this research. We also expect this tool to support Customer Service Representatives (CSRs) in their work on behalf of customers.

PGE's hypothesis is that the information tool will reveal energy-reducing strategies that the customer finds valuable to implement. For example, the tool will determine the cost of running a "spare" refrigerator, or determine the bill reduction from reducing the thermostat setting by a few degrees. The tool might lead the customer to discover unnecessary, but always-on devices. These types of strategies could reduce total energy use by 1% to 10% annually. In a program aimed at getting 500 customers per week to use the tool, if 40% of the customers implement an average, 4-year sustained annual usage reduction of 2.5% (or about 250 kWh per year), then the typical year benefit after four (4) years would be about $500,000[8] per year. PGE estimates utility costs, including depreciation of the development and recurring annual costs to be approximately $110,000. Uncertainty exists with all variables implying a wide range in the benefit outcome. Sensitivity in the summary Table 1 is based on customer participation varying from -50% to +100%.

The main objectives of the project, by phase, will be:
Phase 1:

- Conduct primary research, develop concepts for information tool, and create requirements.
- Select a vendor suitable for PGE's objectives.
- Create the initial infrastructure to link meter information, an analysis engine, and a web interface for customers and CSRs.
- Focus on aiding the high-bill complaint process.
- Begin interval data collection for the initial customers that will test the Phase 2 information tool.

Phase 2:

[7] $1,600,000 = 15,000*(($60+$15) 0.8*$40)
[8] Based on an avoid energy cost of $50/MWh. 500,000 = $50/MWh * 4* (500 Customers/wk * 40% * 50 wk/yr * 250 kWh saved annual per customer)/1000. See Attachment 2 for calculation details.

- Develop a tool to help customers understand the cost drivers of daily appliance usage and their own behavioral choices.
- The tool will create semi-customized recommendations to save energy.
- Track energy use for customers that use the tool.
- Conduct an evaluation to determine if the information tool makes a sustained and quantifiable impact on the customer's energy use.

The milestones in this project are:

- Second quarter 2007 – Complete research and sign contract with vendor.
- Fourth quarter 2007 – Launch initial application for high-bill complaint process.
- Fourth quarter 2007 – Begin interval data collection for target group of 20,000 customers.
- Second quarter 2008 – Develop and test-launch interval-data dependent information tool.
- Third quarter 2008 – Test tool with customers and make improvements to usability.
- Fourth quarter 2008 – Launch information tool to target customers, with at least 8 months of interval data history. Promote tool sufficiently to get 1,000 participants in first 3 months.
- Third quarter 2009 – Conduct statistical analysis to determine impact of information tool on energy use.
- Fourth quarter 2009 – Make information tool available to all PGE customers.

Improved Distribution Asset Utilization

The underlying assumption in the topics discussed below is that the availability of hourly interval data at every point of delivery will allow PGE to compile a detailed load profile on each component of our distribution infrastructure (e.g., every tap line, service transformer, feeder segment between switches) with the objective of improving asset management and overall system efficiencies. Not included in these estimates is the cost to acquire an analysis tool, sufficiently powerful, to analyze the data.

<u>Avoided Service Transformer Failures</u>

PGE has approximately 300 service transformer failures per year, many of which result from overloading. PGE uses a regression tool to identify overloaded transformers based on estimated monthly kWh usage. The ability to collect interval data on 100% of PGE's service delivery points allows a new model to be developed based on actual hourly loadings which would enable PGE to identify transformers that are overloaded beyond normal tolerances on a more accurate and timely basis.

A new regression model could yield, for each service transformer, an estimate of peak loading (percent of nominal rating) as a function of the ambient temperature at the transformer. We estimate that a new tool might make it possible to eliminate as many as 30% of the failures (i.e., 90 transformers per year) before they occur. This would be especially useful given the increasing amount of home air–conditioning load being added by residential customers. With better data, transformers that are overloaded could be identified and replaced with new or higher-voltage transformers before they fail. This enables PGE not only to re-use the transformer at another location but also to be more efficient in planning and scheduling replacements.

To determine a potential benefit, we assume that the current cost to replace a failed service transformer is $500 plus a 3-man crew working two hours at an average cost of $315/hour (including overtime). This results in a cost of $1,130 per transformer. With a planned replacement, no overtime is required and several transformers can be exchanged per trip. Instead of a two-hour emergency replacement, the planned replacement is assumed to be a 1-hour event at an average cost of $270/hour instead of $315/hour. This results in an average savings of $860 per replaced transformer, or typical annual net savings of approximately $77,000 (90 * $860).

In addition, if we assume a reduced customer outage time of 3 hours, an average of four customers affected per transformer, and a $15/hour avoided societal cost per customer during the outage, the societal benefit is about $16,000 per year (90 replacements x 4 customers x 3 hours x $15/hour). Uncertainty in the 30% pre-identification rate puts total net benefit in the range of $40,000 to $200,000.

<u>Delayed Feeder Conductor Work</u>

PGE currently plans approximately $1 million of feeder conductor work per year. These are performed to resolve overloading conditions on sections of the affected feeder.

Assume that PGE defers one-third of its annual work to upgrade feeder conductors, an amount of $333,000, for three years because improved loading data were available from AMI. This is based on an engineering estimate. The estimated reduction in revenue requirement (using a 0.13 multiplier) on deferred hardware costs is approximately $43,000 per year. The additional engineering cost of collecting AMI data by conductor segment could be approximately $25,000 per year. Based on these assumptions, a net benefit can be achieved by year three and for ongoing years of approximately $100,000 per year (see table below).

Benefits	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Year 1 Work Deferred	$43,000	$43,000	$43,000	---	---
Year 2 Work Deferred	---	$43,000	$43,000	$43,000	
Year 3 Work Deferred	---	---	$43,000	$43,000	$43,000
Year 4 Work Deferred	---	---	---	$43,000	$43,000
Year 5 Work Deferred	---	---	---	---	$43,000
Engineering Cost	($25,000)	($25,000)	($25,000)	($25,000)	($25,000)
Net Benefit	**$18,000**	**$61,000**	**$104,000**	**$104,000**	**$104,000**

The net benefit is very sensitive to the percent of work that can be deferred each year. The range of typical net benefits would be about $40,000 to $160,000.

Improved Outage Management

Avoided Trouble Calls

PGE estimates that for 10% of trouble calls[9] from customers reporting that their power is out, it is subsequently discovered that no PGE outage occurred. These trouble calls could be avoided using the query function in the AMI meter which can determine whether or not power is being delivered to the meter (i.e., customer premise).

To estimate the range of benefits, we assume the cost of a truck and full time employee (FTE) to be approximately $90/hour. If improved outage management capabilities from AMI save one hour at $90 for 10% of PGE's 2,500 outage calls per year, we would save approximately $22,500 per year. The costs to implement the power status check at the meter include training for the 200 employees who respond to customers and automating the assisted look-up functionality in the affected systems. This could require approximately $10,000 to $20,000 in incremental costs. The primary uncertainty variable in our assumptions is the number of avoided truck dispatches. A range of minus 50 percent or plus 30 percent implies a net benefit range of $10,000 to $30,000 per year.

Faster One-Premise Outage Response

With isolated outages involving only one premise, the time between outage occurrence and notification at PGE is currently expected to be longer than for outages affecting multiple customers. This expectation is based on the likelihood of people being away from their homes during work hours and returning to find that their home is without power. For customers, the effects of the longer outage could have consequences; for example, spoiled food, lower productivity in a too cold or too warm house, etc. With the proposed AMI system, Operators can identify instances of isolated outages and create a service order to initiate repairs without having to rely solely on notification from the customer.

Annually, approximately 3,000 outages occur that affect only one customer. If we assume that 25% occur when the customer is not at home and that the average incremental cost impact to these customers is at least $15 per outage, the resulting societal benefit would be approximately $12,000 per year, plus or minus 50%. PGE, however, does not yet have an estimate for the cost to integrate AMI with the Outage Management System (OMS). Another consideration is that PGE would have to verify the reliability of the AMI outage data because undetected outages and false positive reports would affect the benefit estimate.

Improved Storm Management

This benefit would avoid the costs to address customers who remain without power after a line crew restores power on their tap line, because the AMI system can detect any remaining, isolated customer outages before the crew leaves the area. Restoring the customer service without having to return later saves approximately one hour for a three-man, two-truck crew.

[9] Based on random sample of 2005 Outage Management System (OMS) data.

Assumptions made include the following:

1. One Level 2 outage (affecting 25,000 customers) every year.
2. A Level 3 outage (affecting 100,000 customers) every 5th year.
3. An average of 50 customers restored per crew repair.
4. 10% of repairs leave a customer still out of service.
5. The cost is $315/hour for crew and truck cost[10].

These assumptions imply an average savings of approximately 90[11] crew hours per year, or a cost savings during the storm of approximately $30,000 per year (90 hours x $315/hour). For societal benefits, we assume the customers experiencing the undiscovered outages have five additional hours of outage time. This means approximately 360 customer outage hours could be saved. With an average societal outage cost of $15/hour per customer the societal savings is another $7,000 per year.

The key uncertainties in this analysis are the average number of isolated outages detected by the AMI system in a Level 2 or Level 3 outage, the avoided crew hours from not having to return to the site, and the average extended duration of the outage for the customer. Varying the key variables by minus 50% or plus 50% results in a large range of benefits of $0 to $75,000 per year.

There are unknown costs for information system modifications to: (1) automate meter status checks by distribution element, e.g., by fuse, switch, and (2) improve the quality of electrical connectivity records to ensure accurate analysis. To calculate net benefits, $100,000 in development work is assumed recovered with a 0.20 revenue requirement factor[12].

Faster Fault Location Identification

About half of PGE's SAIDI[13] (System Average Interruption Duration Index) duration is the result of faults that occur when a substation feeder breaker locks open on a downstream fault. Finding the downstream fault, especially on long rural feeders, is a time-consuming process.

A business partner of our AMI vendor is currently developing a fault detection device that would communicate through PGE's proposed AMI system and help pinpoint the location of faults. If PGE places an average of fifteen (15) fault detectors at strategic locations on our longest 450 feeders (covering about 95% of all customers), then the amount of time required to determine the location of a fault should be reduced considerably. The installed cost of a fault detection device is about $250 to $350 per telemetry point (including a system to report the fault data to the

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[10] For a general outage, we assume our personnel costs based on 50% straight time and 50% overtime. Distribution line workers cost an average of $90/hour for straight time and $120/hour for overtime (including vehicle, equipment and payroll loadings), for an average of $105 per person per hour. Thus, a three-person crew costs an average of $315/hour when responding to a general outage.

[11] Based on the first 4 assumptions 90 = (25,000 + 100,000/5)/50 * 10%.

[12] A multiplier to calculate estimated typical year revenue requirements. We use a multiplier of 0.2 for software and 0.13 for hardware.

[13] SAIDI is the average annual outage duration for each customer, calculated as the sum of all customer interruption durations during a year divided by number of customers served. PGE's 2005 SAIDI was 86 minutes (1.43 hours).

dispatchers); thus, the installed cost of 15 such devices on each of 450 feeders would be $1.7 to $2.3 million. This implies an annual cost of about $260,000 (0.13* $2.0 million).

PGE has about 250 open breaker events per year and we typically assign a three-person crew to locate the fault. We assume the current outage duration is 60 minutes per incident and the average reduction in outage time would be 20 minutes. We further assume fault detectors will aid detection on 80% of these events. Based on average crew costs of $315/hour, PGE would save about $21,000 per year (-0.333 hours x 200 feeders x $315/hour). In addition, these 200 events affect, on average, about 2,000 customers each; thus, PGE could reduce overall customer outage time by about 130,000 hours per year (200 events x 2000 customers x -0.33 hours per customer). Assuming an average societal loss of $15.00 per customer per hour, this saves about $2 million per year. Including the societal savings, there is a one-year payback. The main uncertainty rests with the actual reduction in the time to locate the fault. With a range of 10 to 30 minutes in outage reduction time, the typical year net benefit is $0.8 to 2.7 million.

<u>Reduced Contact Center Cost</u>

Overtime costs at PGE's Contact Center during major storms runs as high as $3,500/hour. Over a typical three-day event, overtime costs can total as much as $50,000. As customers begin to understand and trust the capability of the AMI system to detect outages and facilitate faster restoration of service, in-bound call volumes might go down -- as might the need for CSRs to call back customers to verify restoration.

An average annual benefit of $10,000 per year is estimated based on the assumption that improved outage management and reporting will reduce the incidence of customer calls and re-calls by 20%. However, these benefits must be judged against unknown information system costs to facilitate the needs of customers and CSRs. The implementation plan for this initiative is to better quantify the benefit and to identify specific scenarios where benefits could be realized. After generating a list of the information and/or resources that customers and CSRs need to aid their outage-related inquiries/needs, a gross estimate for the information system support cost will be made.

IV. Timetable

The table below shows, for each of the initiatives discussed above, net annual benefits, societal benefits, net present value AMI benefits, and the due date for the initiative's implementation plan. The plans will recommend either a test demonstration to validate key benefit/cost assumptions (of a program-level implementation), or an actual program implementation.

One objective in creating the implementation plans will be to improve our estimates of the costs and benefits based on additional research. Actions to be completed in producing each implementation plan include:

- Complete research regarding cost and benefits including, where appropriate, examining other utility programs.

- Outline the specific process changes required to implement a full program, and also the simplified set for the demonstration, if warranted.
- Identify the key assumptions that need to be validated in a demonstration (if one is proposed) to justify moving forward with a full program implementation.
- Produce a benefit/cost analysis for the demonstration, and also for the full program assuming the key demonstration hypotheses hold true.
- Explain risks associated with implementation if any.
- Provide a timeline for completion of major milestones if the initiative were to move forward.
- Present the economic analysis for the initiative, timeline, and a recommendation to proceed, or not, to OPUC by the due date below.

If terms, mutually agreeable to PGE and OPUC, are reached regarding implementation, then PGE will provide within four months, any additional details required to effect a planned implementation.

Table 1 Estimated Range of Net Benefits

Initiative Category	Net Benefits[14] (thousands)	Societal Benefits[15] (thousands)	NPV AMI (millions)	Plan Due Date
Demand Response Market Pilot	$0-2,300	[16]	$0 - 27	Sept 2007
Appliance Market Transformation	$0-500	[17]	$0 - 5	Aug 2007
Info-Driven Energy Savings	$150 - 800		$2 - 9	July 2007
Avoided transformer failure	$30-170	$10-30	$0.4 – 2	June 2007
Deferred Feeder Conductor Work	$40-160		$0.4 – 1.6	Sept 2007
Improved Outage Management	- - Typical Year Benefits - -			
-Avoided Trouble Calls	$10-30		$0.1 – 0.3	Sept 2007
-Faster One-Premise Response	-	$10-20	$0.1 – 0.2	June 2007
-Improved Storm Management	$0-75	$60-200	$0 – 0.8	Sept 2007
-Expedite Fault Location	($240) [18]	$1,000-3,000	$9 - 30	Sept 2007
-Reduced Contact Center Cost	$10		~ $0.1	June 2007

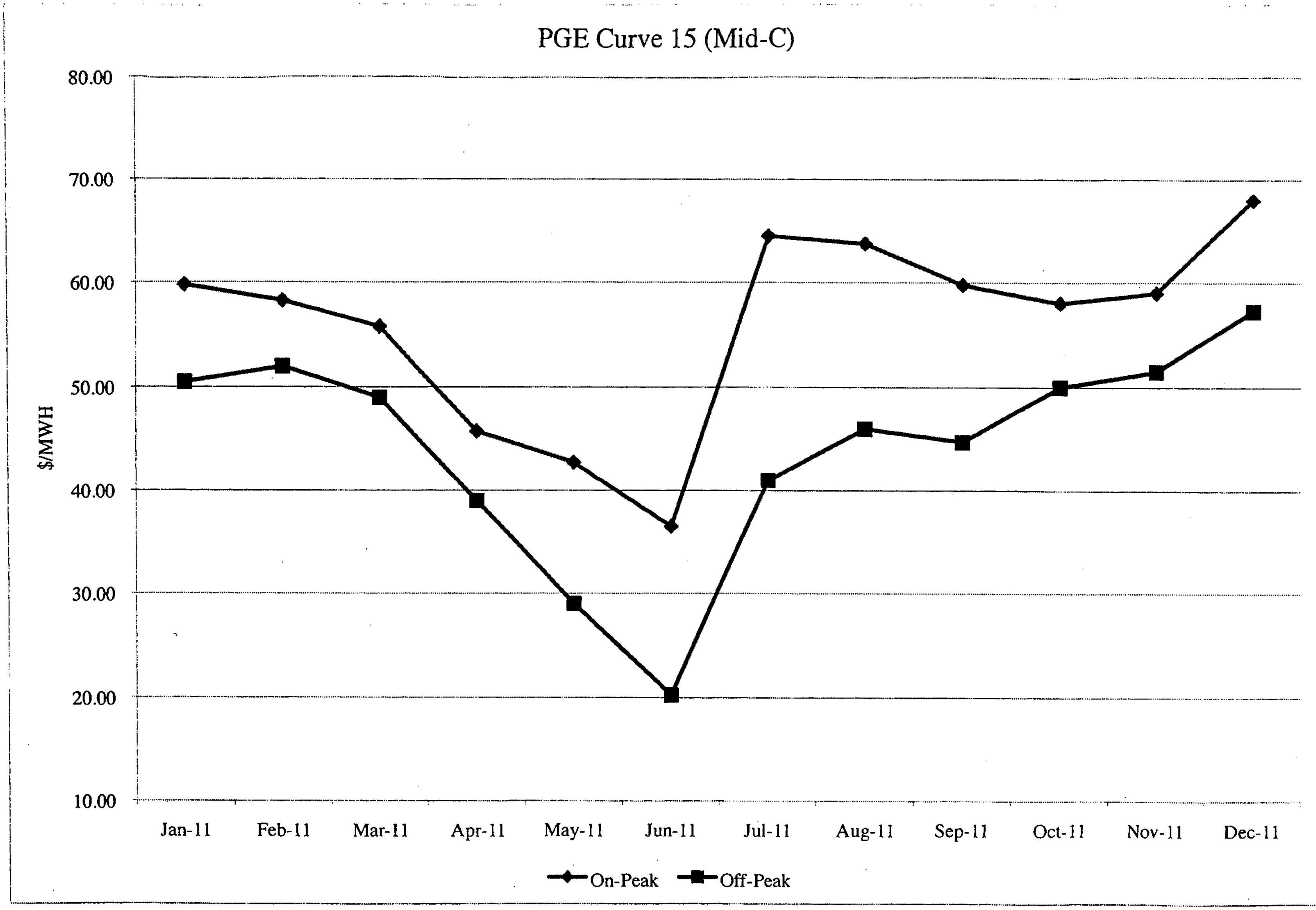
[14] These estimates are assumption-driven with large uncertainty around the number of customers that will actually participate. Some of the scenarios produce negative net benefits.

[15] Dollar amounts listed are based on an average cost to customer during an outage of $15/hour for lost productivity and/or specific losses, e.g. food spoilage.

[16] The benefit would be reduced if the customer incurs incremental costs to purchase controls, e.g., water heater timer, programmable thermostat, etc. to moderate the personal attention required.

[17] If this demonstration were to influence the adoption of a national appliance standard, PGE believes the long term societal benefit would exceed the entire cost of the AMI system multiple times.

[18] Most costs are recovered from the assumed societal benefit; utility benefit alone does not justify installation.


PGE Curve 15 (Mid-C)
$/MWH
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
Jan-11
Feb-11
Mar-11
Apr-11
May-11
Jun-11
Jul-11
Aug-11
Sep-11
Oct-11
Nov-11
Dec-11
On-Peak
Off-Peak

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THE INFORMATION MAY BE SHOWN ONLY TO QUALIFIED PERSONS AS DEFINED IN ORDER NO. 10-056 AND IS BEING PROVIDED TO SUCH INDIVIDUALS.

TOTAL STREET LIGHT CIRCUIT COUNTS
2004 AND 2009

CITY OF PORTLAND STREET LIGHT CIRCUIT COUNTS
2004 AND 2009

CERTIFICATE OF SERVICE

I hereby certify that I served the foregoing City of Portland's Intervenor Comments and Exhibits on the individuals listed below in Docket No. UE 215 on this 4th day of June, 2010.

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