ORDER NO. 08-245

ENTERED 5/05/08

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 189

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request to Add Schedule 111, Advanced Metering Infrastructure (AMI).	)))))))	ORDER

DISPOSITION: APPLICATION GRANTED

I. INTRODUCTION

In this docket Portland General Electric Company (PGE or the Company) seeks authority to implement its proposed Schedule 111, "to reflect the net costs related to the deployment of an Advanced Metering Infrastructure (AMI)." Following workshops, settlement conferences, informal contacts, and the filing of prepared testimony, several parties have reached a settlement and stipulation. The stipulation is attached as Appendix A and incorporated by reference. Parties to the settlement are PGE, staff of the Public Utility Commission of Oregon (Staff), the Community Action Partnership of Oregon (formerly the Community Action Directors of Oregon) (CAPO), the Oregon Department of Energy (ODOE), and Northwest Natural Gas Company (Stipulating Parties). The Citizens' Utility Board of Oregon (CUB) opposes the settlement.

The AMI project includes installation of new solid-state electronic meters and a fixed two-way communications system that allows for the automated collection of metering data and for sending signals to the meter. The system is intended to reduce costs, improve service, and provide a platform for additional demand-side management programs. If approved, installation would begin promptly, to be completed in 2010.

II. PGE/STAFF/ODOE'S JOINT POSITION

PGE, Staff, and ODOE (Joint Parties) filed joint opening and reply briefs in support of their stipulation. They state that the financial projections and financial analysis of the AMI project have undergone "intense scrutiny." These projections show a net present value benefit to customers of approximately $33 million over 20 years. Other customer and system benefits attributable to the AMI platform are estimated to increase the net present value to a range of $37 million to $80 million over 20 years.

The stipulation includes 12 pages of proposed AMI conditions settling all issues raised by the stipulating parties. In their brief, the Joint Parties offer the section headings of the stipulation to illustrate its breadth:

- Operational Implementation Plans
- Customer and System-Related Benefits
- Demand Response
  - IRP Capacity Planning
  - Voluntary Critical Peak Pricing
  - Appliance Market Transformation
  - Information-Drive Energy Savings
- Distribution Asset Utilization
- Avoided Service Transformer Failures
- Proper Transformer Sizing
- Delayed Feeder Conductor Work
- Outage Management
  - Avoided Trouble Calls
  - Faster One-Premise Outage Response
  - Improved Storm Management
  - Faster Fault Location Identification
- Regulatory Filings
- Coordination with Northwest Natural Gas Company in Joint Meter Reading Area
- Community Action Partnership of Oregon and Oregon Energy Coordinators
  - Association Conditions
  - Remote Disconnect/Reconnect
  - Leveraging Data
  - Long-Term Benefits of AMI Functionality
  - Limited Service Delivery
  - Pre-Paid Electric Metering
  - Status Reporting

The provisions of the stipulation were described and explained in the joint testimony in support of the AMI stipulation, sponsored by Lisa Schwartz and Carla Owings of Staff and Alex Tooman of PGE.

According to their testimony, the capital costs of AMI will be about $132.2 million, including radio frequency meters ($70 million), remote disconnect meters ($19.3 million), meter installations ($20.1 million), and system development ($9.0 million). The remaining costs are attributable to servers and storage, network installation, licenses, handhelds, and other items.

PGE claims that AMI will provide two types of benefits. First, it provides operational costs savings, which PGE estimates at $18.2 million in the first full calendar year after deployment. These savings are calculated as follows:

Labor Cost	$10,967,000
Non-labor Cost	956,000
Late Fees	1,737,000
Energy Unaccounted For	3,632,000
Power Cost Savings	1,387,000
Other Savings	(515,000)
Total Projected Savings	$18,164,000.

Second, PGE claims that AMI also provides customer and system benefits, derived from programs that the system supports, or may be developed. These would include demand response, distribution asset utilization, and outage management. While these benefits have the potential to produce significant cost savings, their implementation would require additional investment.

PGE's proposed tariff reflects about $12.9 million for the net annual revenue requirement impact of the AMI, including accelerated depreciation of the old metering system, and operation and management (O&M) savings during the deployment period.[1] That amount represents a 0.8 percent increase in PGE's revenue requirement as determined by the Commission in PGE's last general rate case.

For rate recovery, PGE allocated the total revenue requirement into three components: recovery of the costs of the new equipment, accelerated depreciation of existing meters, and O&M savings. PGE calculated the percent to which each of these three categories contributes to the total revenue requirement, and applied those percent contributions to the annualized revenue requirement. Using that method, PGE allocated $4.5 million to the existing system, $12.5 million to the deployment of the new AMI meters, offset by a $4.1 million reduction attributable to O&M savings. For residential customers, the percentage change in revenue requirement is 1.2 percent. For small non-residential customers, the percentage change is 1.4 percent. For most large customers the percentage change is a "fraction" of 1 percent.

The tariff proposal reflects the magnitude of the project and its associated accounting treatment. The plan will take over 2 ½ years to fully implement. Most of the costs will not be charged initially to construction work in progress and then closed to plant when the project is completed. In this case, the meters, which comprise over 80 percent of the investment, will "immediately close to plant" when received by PGE. Without either the tariff or annual rate cases, PGE would receive no recovery on the new system during deployment.

[1] Included in the accelerated depreciation of existing meters are Network Meter Reading (NMR) meters deployed as part of a network metering program approved in docket UE 115. The meters were intended to support direct-access or to provide cost-effective meter readings in remote areas.

Only part of the proposed system was deployed. The costs of that system have been included by PGE in its rates. Because the full system was not deployed, PGE refunded to customers the difference between the projected and actual costs, from 2003 to 2007.

The Joint Parties state that the accelerated depreciation of old meters is consistent with prior Commission orders. They cite earlier dockets where PGE proposed plans for its NMR system and began the accelerated depreciation of its older meters, in anticipation of full deployment. The AMI project's net benefit includes the cost of the accelerated depreciation of the old meters.

The AMI project is structured in a manner that the parties believe avoids conflicts with ORS 757.355.[2] The recovery of the new system occurs slower than the rate of deployment, while the accelerated depreciation of old meters occurs faster than the rate of replacement.

The recovery of the new system incorporates a six-month lag in recovery of new AMI costs, with rate base adjusted monthly during the deployment period. The recovery of the old meters is accomplished by applying most of the accelerated depreciation of the old system at the front-end of the tariff. Together, these provisions allow for the revenue requirement to be levelized over the deployment period.

Through 2010, the AMI will be part of PGE's rate base. PGE also will be realizing the full operating benefits described above. After 2010, PGE will file a general rate case at the Commission's request that will capture the operating benefits on behalf of customers, if the Company is not already engaged in such a proceeding.

In reaching their settlement, the parties reached agreement on implementation issues raised by Staff. These include the ratemaking treatment of vehicles used for meter reading as AMI is deployed, while also revising PGE's vehicle purchasing strategy.

Staff raised an issue relating to updates to PGE's financial analysis. The parties agree that PGE performed those updates and that those updates provide the final estimates for AMI costs and benefits, and the net present value (NPV) of the project. Those values are adopted in the stipulation.

Staff raised an issue regarding the mitigation of AMI rate impacts during the deployment period. The proposed effective date of the AMI tariff coincides with the expected Senate Bill 408 credit (June 1, 2008), which is expected to offset the rate impact of the AMI tariff.

PGE provided Staff a draft scoping plan that identifies and quantifies additional customer and system benefits not included in the direct benefit analysis. The stipulated conditions address Staff's concerns regarding operational implementation plans, customer and system benefits, direct load control and time-varying pricing

[2] ORS 757.355 provides, in relevant part: "a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer."

programs, regulatory filings, and coordination with Northwest Natural in the joint meter-reading area.

PGE provided Staff with work papers that demonstrate that PGE used its signed AMI contacts as the basis for its cost estimates for meter equipment and installation in its financial analysis.

The Stipulating Parties agree that PGE has addressed all of CAPO's issues relating to low-income customers, including each of the following: remote disconnect/reconnect, earlier reconnection than specified in the Oregon Administrative Rules, customer payment/agency commitment processing, limited service delivery, leveraging data, long-term benefits of AMI functionality, and pre-paid metering.

The Stipulating Parties agree that PGE has addressed issues raised by Northwest Natural relating to coordination in joint meter-reading areas.

III. CUB'S POSITION

CUB argues that PGE's AMI project is not based on a mature technology. CUB cites developments in California, where utilities are proposing widespread deployment of AMI systems. According to CUB, the decisions in California are based on utility business cases that "dwarf" PGE's in depth, and that rely on time-of-use pricing to achieve cost-effectiveness, unlike PGE's. CUB argues that the California model supports a "deliberate" process in Oregon.

CUB is concerned that PGE's AMI technology will not have the functionality to directly control load – "one of the more exciting opportunities that advanced meters could provide." CUB cites testimony by the Joint Parties to the effect that PGE's system can be updated to use a "standard protocol" for load control. However, CUB is concerned regarding the likely cost of such upgrades, particularly "given the slim margin of projected net benefit[s]" for the basic system. In CUB's terms, such improvements would amount to PGE's third advanced metering installation since late 2001.

CUB notes that inherent in every business plan is the risk that benefits may not materialize as foreseen. PGE and Staff appear to be comfortable that the net benefits will materialize, as planned – CUB is not. CUB claims that PGE intends that its customers will take all of the business risk of the AMI project, and pay for the premature replacement of the earlier advanced NMR meters.

CUB states that the projected net benefit of $33 million over 20 years "is a slim margin when compared to the risks of technology or price changes" associated with the project. CUB compares that total benefit to PGE's projected net variable power cost for 2008 – $745 million – to make the point that "there is little wiggle room" for the projected favorable outcome.

CUB objects to any advanced approval for PGE's prudence in undertaking the project. CUB notes that even the parties that have joined PGE in the stipulation relied on PGE's business plan. CUB makes a distinction between agreeing that PGE's business plan appears reasonable, and agreeing that the Company prudently formulated its business plan. CUB observes that this Commission cannot bind future commissions, in any event.

CUB objects to the write-off of the docket UE 115 advanced meters (UE 115 meters) as a ratepayer expense. CUB notes that PGE earns a rate of return to manage its business risks. PGE should be responsible for its past project choice.

CUB argues that customers should not pay for either the accelerated depreciation of the UE 115 meters, or for the annual O&M costs necessary to use those meters with the newer system. According to CUB, it would be "bad regulatory policy" to insulate PGE from the consequences of its investment choices. If the Commission were to decide to allow PGE to recover the UE 115 meter costs, CUB argues that the Commission should reduce PGE's allowed return on equity, to reflect its lower risk.

CUB makes a distinction between the UE 115 meters and the conventional meters that otherwise are deployed across PGE's system. In the one case, the utility is making a fundamental change in its metering "platform." In the other case, the utility would be simply replacing older meters with newer ones – prematurely.

CUB notes that 60 percent of PGE's projected operational savings in its business plan comes from the reduced labor costs resulting from no longer having to read meters manually. That savings already has been realized for the UE 115 meters.

CUB applies ORS 757.140(2) and argues that the proposed retirement of the UE 115 meters would not be in the public interest.[3] CUB notes that premature retirement of the UE 115 meters would not be due to factors enumerated in ORS 757.140(2)(a), leaving the Commission only with the blanket provision: "[W]hen the commission finds that the retirement is in the public interest."

CUB states that a measure of public interest is net benefit – if the continuing costs of operating the plant are greater than costs associated with retiring the plant, there is a net benefit to closure. However, net benefits themselves do not necessarily support full cost recovery from ratepayers.

[3] ORS 757.140(2). In the following cases the commission may allow in rates, directly or indirectly, amounts on the utility's books of account which the commission finds represent undepreciated investment in a utility plant, including that which has been retired from service:
(a) When the retirement is due to ordinary wear and tear, casualties, acts of God, acts of governmental authority; or
(b) When the commission finds that the retirement is in the public interest.

CUB cites the Commission's Trojan decision (Order No. 95-322) to support its view that "net benefits" must encompass more than lower costs. The lower cost standard implies that a poorly run plant could be shut down as a least-cost option, allowing a utility to shift the capital or operating costs of its own imprudence to ratepayers.

According to CUB, PGE's decision pursuant to UE 115 to go ahead with a "second-choice advanced metering system," well before advanced metering technology had matured, only increased the likelihood that premature retirement of those meters would produce a net benefit in the current proceeding. The Commission should not "wash out" a poor management decision with a net benefit finding.

In that light, CUB argues that PGE has not proven a net benefit to replacing the UE 115 meters. CUB notes that none of the operational savings reported in PGE's business plan would seem to apply to the retirement of the UE 115 meters, because all of those benefits also would be realized with the advanced meters already deployed.

Thus, CUB argues that the premature retirement of the UE 115 meters would not qualify for rate recovery under ORS 757.140(2)(b), even if the Commission were to approve PGE's proposed AMI program. In CUB's view, it is not in the public interest for the Commission to allow utilities to invest in new technology, only to replace that technology with newer versions.

CUB recommends the Commission reject the stipulation and decline PGE's request for "pre-approval" of its proposed AMI project. If, however, the Commission approves the proposal, CUB recommends against accelerated depreciation of the UE 115 meters. Further, CUB recommends the Commission make clear that PGE's business case and its execution are open to prudence examination in the future.

IV. PGE/STAFF/ODOE'S JOINT RESPONSE TO CUB

The Joint Parties dispute CUB's claim that the proposed technology is not "mature." They describe the expected deployment of AMI systems in other jurisdictions, including sales by PGE's vendor, to show that California is not the only market for such products.

They note that it is highly likely that new features will be available in the future, but, if PGE were to wait for new technology, the AMI project might never be undertaken. The technology available for this project will provide the functionality and benefits projected.

The Joint Parties believe that CUB misunderstands their testimony regarding upgrading the system to incorporate a standard protocol that may be developed at a later date for communication with smart appliances. They state that PGE only would seek approval for cost-effective changes to the system, such as a "communication bridge," to incorporate a standard protocol. They cite their testimony to the effect that the proposed system would be able to communicate with load control switches on appliances and thermostats, even without the standard protocol.

The Joint Parties state that CUB's comparison of the $33 million in net benefits to PGE's projected 2008 net variable power costs "is a meaningless comparison." The $33 million in savings is significant, and is "more noteworthy" because it incorporates the cost of paying off the old system. On its own, the AMI system is predicted to generate a net present value of over $66 million, not including any potential demand response benefits the AMI project enables.

The Joint Parties state that CUB misconstrues PGE's position regarding prudency reviews. PGE cites its testimony to the effect that all parties have the right to address AMI costs and benefits and that "the costs and benefits will be subject to a prudence review." The only decision before the Commission at this time is whether it would be prudent for PGE to proceed with the installation of the AMI system.

Regarding the write-off of the UE 115 meters, the Joint Parties suggest that CUB has ignored uncontested facts and basic ratemaking principles. The parties do not see a legal or policy reason why cost recovery of the meters on an accelerated basis would be improper but recovery over a longer period would be proper. Under recent court decisions, PGE believes that absent accelerated recovery, there would be an unfair impact because it would not be allowed to earn a return on the investment after it is removed from service. If those meters are not replaced, PGE's annual O&M costs would be greater by $600,000. In addition, capital costs would increase to keep the components functional.

The Joint Parties state that only part of the NMR system approved in docket UE 115 was deployed due to changes in circumstances and that the UE 115 meters have been used and useful since their deployment. However, it is cost effective to replace those meters now, as evidenced by the $600,000 per year savings. They argue that their proposed treatment does meet the standard of ORS 757.140(2).

The Joint Parties note that CUB argued that PGE can proceed without Commission approval, if it is confident about its business case. However, they argue that, for PGE to be able to recover the remaining depreciation of existing meters, ORS 757.355 requires that the Company do so prior to the retirement of such equipment. Therefore, PGE must request such treatment before installing its new AMI system.

V. DISCUSSION

Whether to deploy automatic meter-reading technology to residential and business customers depends largely on whether such an investment would be cost effective. The Joint Parties believe that their analysis proves that PGE's program would be cost effective and should be approved. CUB disputes their analysis.

In this case the "cost effective" test may be applied in two stages. In the first stage, the Joint Parties have shown that the investment in the AMI technology would be cost effective, even if it were simply a matter of substituting the new meters for the old (including the early retirement of the UE 115 meters). In the second stage, 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. These benefits could not be realized without the deployment of the devices. To the extent that these measures likewise are cost effective, their realization likely would make the first stage economic, even if it were not cost effective by itself.

The Commission's adoption of the settlement does not merely allow the AMI technology to be installed and the UE 115 meters to be written off. It also obligates PGE to meet the "Proposed AMI Conditions" set forth in Exhibit 101, sponsored by PGE witness Tooman and Staff witnesses Schwartz and Owings in support of the stipulation. Through PGE's performance of the specified conditions, the benefits to be realized from adoption of the settlement may be much greater than the savings used to justify the first stage.

The section headings for the conditions are set forth above. As PGE moves ahead to meet those conditions, we will follow its progress. We expect that the parties to the stipulation (and CUB) will hold PGE to these performance standards, and we will entertain a complaint from any party that believes that any condition is not being met. Because the conditions are a material part of our order adopting the settlement, any material change in the terms of the conditions will require Commission approval.

Some of the conditions will require further action before they can be implemented. PGE has committed to filing a critical peak pricing tariff for the Commission's consideration. Whether to approve such a tariff is a matter that will be taken up at the appropriate time. Other rate design refinements will be entertained as may be reasonable.

PGE has committed to investigating load control measures. Again, whether to implement such measures is a matter that will be taken up at the appropriate time. PGE will have the burden of proving that any such proposed measures are cost effective.

CUB requests that the Commission "make clear that PGE's business case and the Company's execution thereof are open to prudence examination in the future." PGE's business case has been examined in this docket and has been found adequate to support the deployment of PGE's proposed AMI technology.

The Commission does not foreclose future consideration of the prudency of PGE's actions taken in furtherance of its business plan. In the event that the projected benefits are not realized, parties may investigate the circumstances and propose appropriate measures for the Commission's consideration.

However, premature early retirement of meters itself is not evidence of imprudence. The Commission's decision to allow for accelerated depreciation of the UE 115 meters does not suggest that PGE was imprudent in proceeding with the UE 115 metering project. Early retirement of plant for the benefit of the ratepayers is not evidence of imprudence.

The terms of the stipulation are reasonable.

The settlement is adopted.

ORDER

IT IS ORDERED that Portland General Electric Company's request to add Schedule 111, Advanced Metering Infrastructure, is approved. Advice No. 07-08, subject to the conditions of the stipulation attached as Appendix A, shall be allowed to go into effect June 1, 2008. PGE is granted leave to proceed with its planned deployment of AMI technology, subject to the terms of the settlement adopted in this order.

Made, entered, and effective MAY 0 5 2008.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

BEFORE THE PUBLIC UTILITY COMMISISON OF OREGON

UE 189

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request to Add Schedule 111, Advanced Metering Infrastructure (AMI)	)	STIPULATION

This Stipulation ("Stipulation") is among Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("Staff"), the Community Action Partnership of Oregon (formerly the Community Action Directors of Oregon), the Oregon Department of Energy, and Northwest Natural (collectively, the "Stipulating Parties").

I. INTRODUCTION

On March 7, 2007, PGE filed Advice No. 07-08 to add Schedule 111, an adjustment schedule to collect costs related to deployment of an Advanced Metering Infrastructure ("AMI"). PGE has since requested an effective date of June 1, 2008, for Schedule 111. Pursuant to the schedule set by the ALJ in this matter, PGE filed testimony supporting its filing on July 27, 2007. That testimony, which incorporated some testimony filed in a previous docket, explained the costs and benefits of the AMI project. PGE has also provided to parties, and the parties relied on in entering into this Stipulation, draft Implementation Plans for the project, draft and signed contracts for AMI equipment purchase and installation, a draft scoping plan related to customer and system benefits, and an updated financial analysis and supporting work papers reflecting the latest estimates of costs and benefits for the AMI project. Workshops have been held and PGE has also responded to numerous data requests from the various parties.

Settlement Conferences were held on July 9, 2007, and October 26, 2007, open to all parties. As a result of those settlement discussions, the Stipulating Parties have agreed to certain conditions associated with the implementation of the AMI project, and with those conditions support for approval of Schedule 111. The Stipulating Parties submit this Stipulation to the Commission and request that the Commission adopt orders in this docket implementing the following.

II. TERMS OF STIPULATION

1. This Stipulation settles all issues raised by the Stipulating Parties.

2. Subject to the provisions below, the Stipulating Parties agree that based on the information provided by PGE to date, and known to the parties, it is prudent for PGE to proceed with implementation of the AMI project, and that PGE should implement the AMI project as set forth in this docket, including the meter purchase and installation contracts provided to the Parties.

3. Attached as Exhibit "A" to this Stipulation are Proposed AMI Conditions (the "Conditions"). The Stipulating Parties have drafted and agreed to the Conditions to address various concerns and issues of the parties. The Stipulating Parties support the adoption and implementation of Schedule 111 as filed by PGE, subject to the Conditions.

4. The Stipulating Parties request and recommend that the Commission approve Advice Filing No. 07-08 subject to the Conditions.

5. This Stipulation does not address PGE's recovery of AMI-associated costs in any future proceeding.

6. The Stipulating Parties agree that this Stipulation represents a compromise of the positions of the parties for purposes of this docket. As such, conduct, statements, and documents

disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding.

7. The Stipulating Parties agree that this Stipulation is in the public interest and will result in rates that are fair, just and reasonable.

8. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks a revenue requirement for PGE that departs from the terms of this Stipulation, the Stipulating Parties reserve the right to cross-examine witnesses and put in such evidence as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

9. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order which is not contemplated by this Stipulation, each Stipulating Party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other Stipulating Parties within five (5) business days of service of the final order that rejects this Stipulation or adds such material condition.

10. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. The Stipulating Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

11. By entering into this Stipulation, no Stipulating Party shall be deemed to have

approved, admitted or consented to the facts, principles, methods or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

12. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 21st day of November, 2007.

Cece L Coleman

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

COMMUNITY ACTION PARTNERSHIP OF OREGON

NORTHWEST NATURAL

OREGON DEPARTMENT OF ENERGY

PORTLAND GENERAL ELECTRIC
COMPANY

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COMMUNITY ACTION PARTNERSHIP
OF OREGON

NORTHWEST NATURAL

Robin Straughan 11/20/07
OREGON DEPARTMENT OF ENERGY

Proposed AMI Conditions
November 2007

These AMI Conditions include specific timing that is based upon a tariff effective date of June 1, 2008. Should that date change, the specific times identified in this document may change accordingly.

Operational Implementation Plans

With respect to the detailed implementation plans PGE has provided regarding the operational improvements enabled by AMI, PGE has or will:

- Quarterly, beginning in April of 2008 and continuing throughout the deployment period, file with the Commission a status report detailing:
  - o progress under the implementation plans, including any significant changes in timing, budget, or scope,
  - o number of meters installed, and
  - o actual costs by category
- If implementation plans are delayed, either due to significant changes made to the overall AMI project scope that affect implementation plans previously provided or to delays associated with the implementation plans themselves, immediately notify the Commission and provide revised implementation plans within 60 days of the notice provided under this condition.
- Filed draft copies of contracts for AMI equipment and equipment installation on July 2, 2007.
- On October 1, 2007 filed signed copies of contracts for AMI equipment and equipment installation, including a redline/strike-out version to highlight differences from draft copies.

Customer and System-Related Benefits

PGE believes 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. AMI is foundational to furthering our goals for demand response and greater energy efficiency. Systems-related benefits derived from deployment of AMI will also add value for customers through more efficient use of utility assets and reduction in costs associated with outages. To obtain the greatest benefit from proceeding with AMI, PGE has or will:

- Appointed a Project Manager to lead the effort in developing Project Charters and Project Plans (implementation plans) in each of the following benefit areas:

  - Information-driven Energy Savings

- Distribution Asset Utilization
- Outage Management

Demand Response initiatives are already being addressed by organizations within PGE and do not need additional project management.

- Provided to OPUC Staff and CUB the Project Charters on June 29, 2007. A meeting was conducted on July 9, 2007 to obtain input and feedback on the charters.

- By May 1, 2008, provide OPUC Staff and CUB the detailed implementation plans (Project Plans). The project plans will include the same level of detail as the implementation plans provided for the operational benefits, with specifics as detailed below.

- After the deployment period and continuing through the conclusion of the first general rate case following deployment, file quarterly status reports on customer and systems-related benefits with the Commission (within 30 days of each calendar quarter) showing savings, costs and operational progress to the previously filed implementation plans.

- Three months following the first and third year after each direct load control program is first offered, file with the Commission a report evaluating each program in the preceding year, including itemized program costs, estimated capacity and costs savings, consumer survey results, and the Company's recommendations for modifications.

- For CPP programs, six months following the first and second year after participants are first offered the pricing option, file an evaluation report with the Commission including program costs, estimated capacity savings, customer acceptance results, and the Company's recommendations on whether to continue, modify or terminate the programs.

Demand Response

PGE's initial efforts to develop incremental demand response will occur through:

- IRP Capacity Planning
- Voluntary Critical Peak Pricing
- Appliance Market Transformation

IRP Capacity Planning

In the IRP that PGE filed June 29, 2007, PGE included in its proposed capacity actions all estimated achievable potential firm direct load control[1] by 2012, under the assumption that this will be the achievable, cost-effective potential that can be reached upon implementation of AMI. Specifically, it includes 23-25 MW of mass market direct load control (ie., from air conditioning, water and space heat), and 80 MW of additional Dispatchable Standby Generation (DSG).

PGE has also included 35 MW by 2012 for firm curtailment among large customers, and critical peak pricing (CPP) tariffs, under the same assumptions of being achievable and cost effective.

To achieve this capability by 2012, PGE has set the following targeted schedule.

- Because our large customers have encouraged PGE to develop a dispatchable peak capacity reduction program, and because of the potential for greater MW among fewer customers more quickly than mass market programs, and because they have the requisite metering capability, the Company has under development a curtailment tariff for its largest customer class (1 MW or greater). The tariff will be proposed by year end 2007. The cost effectiveness of such a program will be determined as part of the investigation of the tariff.
- The next highest potential for cost effective firm demand side capacity during peak periods is among the remaining large business customers. To that end, and where the metering is available, the Company will issue a request to providers of peak demand side capacity to provide proposals under a peak capacity purchase agreement. The development of the RFP is underway and expected to be issued in second quarter 2008, with a tariff following when successful responses are apparent.
- PGE is projecting higher peak loads, in part by the increasing rate of central air conditioning among the residential class. The communications capability of the proposed advanced metering infrastructure will facilitate direct control of major residential appliances such as air conditioners and electric water heaters with additional hardware. Initially PGE planned to issue an RFP for mass market demand side capacity to track with the installation schedule of the advanced meters. This turns out to be cumbersome for direct load control providers as they will not be able to efficiently deploy their installation crews across a targeted customer set over a short duration. Even with a full year of meter installations, a provider may connect only 5-10 MW of their committed load, and would possibly take another year to double that. PGE realizes that mass market direct load

[1] Per *Update of Demand Response Resource Potentials for PGE*, Quantec, February 6, 2007.

control providers will respond more favorably to an RFP that is aligned with the AMI deployment schedule, that is, issued just prior to full deployment of the AMI. Therefore, the RFP will be issued eight months prior to the scheduled full installation of the AMI, or approximately first quarter 2010, with a tariff filed by the end of AMI deployment. In addition to the earlier commitment by large customers, this will provide the needed capacity by 2012.

Voluntary Critical Peak Pricing

AMI meters will support time varying pricing options. PGE is planning to implement an experimental tariff for critical peak pricing once the AMI infrastructure is in place. For a CPP program, PGE will or has:

- Provided to OPUC Staff and CUB, on May 1, 2007, a summary document on Critical Peak Pricing. The document addresses market monitoring of other utility efforts, including the California Statewide Pricing Pilot, examples of possible design parameters, and a sample implementation period. In subsequent discussions the implementation period has since been updated to include a phase for data gathering that was originally omitted.
- Engaged OPUC Staff, CUB and other interested stakeholders in review of program options at a July 9, 2007 meeting and through other discussions and electronic communications.
- The Company estimates that a sampling of meter data can be used for the data gathering phase of a proposed program. After the AMI SAT is completed, approximately 50,000 meters, among all customer classes, will be installed, enough to begin data sampling and gathering.
- Two months prior to 50,000 meters scheduled to be installed, or approximately first quarter 2009, PGE will file an experimental CPP tariff. At least two months prior to filing, the Company will provide a draft tariff to OPUC Staff, CUB, ODOE, CAPO and other stakeholders. The Company also will host workshops to explain the proposed program design and provide an opportunity for informal stakeholder comments.
- As PGE develops its CPP program, the company will evaluate the capability of any programmable communicating thermostats and other demand response technologies for use in both price responsive applications for customers and utility direct load control. The Company will discuss its findings in informal stakeholder workshops in advance of tariff filing and include its evaluation in CPP tariff work papers.

Appliance Market Transformation

PGE clearly understands that as a mid-sized utility in Oregon, we do not have the political power or resources to drive significant market transformation. However, we do believe we can assist in moving towards that transformation by working with an appliance manufacturer with whom we already have developed a relationship to modify an agreed upon appliance to (1) receive price and/or control signals from the utility, and (2) include a simple control 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. To move this effort forward, PGE will or has:

- Engaged regional stakeholders and appliance manufacturers to identify interest in a technology trial for either water heaters or thermostats.
- Assembled a consortium consisting of PGE, our AMI vendor, an appliance or thermostat manufacturer, and other interested parties to develop a project to create a 5 - 10 MW demand response resource through an appliance market-transformation approach that will activate if awarded a USDOE grant by March of 2008. If the grant is not awarded to the consortium, provide a written report to OPUC Staff and CUB detailing barriers to proceeding by May 1, 2008.

Information-Driven Energy Savings

PGE believes that energy usage information derived from AMI interval data will reveal energy savings strategies that customers will value. To test this hypothesis, PGE has performed market research to determine energy usage information. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section for Project Charters and Project Plans, prepare a Project Charter and Plan (implementation plan) to share the results of research to date, the plans for additional research to determine customer interest in energy usage information, and the plans to implement a program to meet customer interest.

Distribution Asset Utilization

The underlying assumption in the area of distribution asset utilization 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. AMI can affect:

- Avoided Service Transformer Failures
- Proper Transformer Sizing

- Delayed Feeder Conductor Work, Including Load Balancing of Substation Transformers

Avoided Service Transformer Failures

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. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, prepare a Project Charter and Plan (implementation plan) to develop this model and apply it to service transformers.

Proper Transformer Sizing

The new regression model described above could also be used to address oversized transformers currently used. PGE has a program today to analyze transformer loading and replace oversized transformers when the replacement is determined to be cost effective. This program uses monthly kWh usage data assembled in the company's TIVO database to estimate the peak loading of these transformers. Use of interval data to more accurately identify peak loading conditions could better determine oversized transformers leading to more effective use of these resources. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, prepare a Project Charter and Plan (implementation plan) to develop this model and apply it to proper transformer sizing.

Delayed Feeder Conductor Work

PGE currently plans feeder reconductor work each year to resolve overloading conditions on sections of affected feeders. With better loading information from AMI interval data on sections and taplines associated with these feeders, some of this work could be deferred or delayed. The better data may allow loads to be shifted to other feeders which could result in a delay in the need to complete the reconductor work. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, prepare a

Project Charter and Plan (implementation plan) to apply the loading information to feeder conductor work.

Outage Management

After the deployment of an AMI system (2010), PGE is planning to upgrade its current Outage Management System (OMS). To ensure proper consideration of outage management improvements enabled by AMI both before and after OMS replacement, PGE will:

- By 2010, develop AMI interface specifications needed to support integration with the new OMS.

Prior to the OMS upgrade, actions that can be taken to improve outage management using the new AMI system will be considered. These actions for consideration are addressed below.

Avoided Trouble Calls

PGE estimates that for a fraction of trouble calls 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). PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, include in an overall Outage Management Project Charter and Plan (implementation plan) application of this query function to avoid trouble calls.

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. 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. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, include in an overall Outage Management Project Charter and Plan (implementation plan) application of this process to improve one-premise outage response.

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's service without having to return later saves outage time and utility costs. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, include in an overall Outage Management Project Charter and Plan (implementation plan) application of this detection function to improve storm management.

Faster Fault Location Identification

Approximately half of PGE's SAIDI (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 PGE's selected 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. Using these devices in conjunction with the AMI system would reduce the time to find these faults significantly and improve SAIDI statistics. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, include in an overall Outage Management Project Charter and Plan (implementation plan) application of these fault detection devices.

Regulatory Filings

PGE commits that if it does not file a general rate case within 12 months of the termination of the UE 189 tariffs, PGE will provide Staff and any interested party a report showing final capture of O&M savings so that the comparison of 'before' and 'after' states does not become too difficult.[2] In addition, after 2010, if PGE is not currently engaged in a general rate proceeding, the Commission may request no later than July 1, 2012, that PGE submit a general rate filing in Oregon no later than eight months thereafter. PGE shall bear the burden of proof in such filing, in accordance with ORS 757.210

[2] This condition does not apply in the event the tariff terminates under Special Condition No. 1 in proposed Schedule 111, Exhibit 202 in PGE's direct testimony filed July 27, 2007.

Coordination with Northwest Natural Gas Company (NWN) in Joint Meter Reading Area

PGE Revenue Operations management has had discussions with NWN management on a periodic basis to inform them of our plans and progress towards deployment of an AMI system and to ascertain their plans for automation within the joint meter reading area. PGE has shared with NWN the specific AMI technology vendor selected and NWN has had several meetings with that vendor to determine whether or not they might consider use of that vendor in the joint meter reading area. To assure coordination that has the least possible financial impact upon customers continues, PGE will:

- Quarterly, beginning in April of 2008 and throughout the deployment period, report to the OPUC Staff and CUB (with a copy provided to NWN) on ongoing coordination discussions between PGE and NWN and actions being taken to assure continued coordination with the least possible financial impact upon customers during deployment.
- Provide preliminary notification of dissolution of the Joint Meter Reading Agreement between PGE and NWN within 30 days of PGE receiving AMI tariff approval from the OPUC and PGE Board approval to move forward with the project.
- Notify NWN no later than 30 days, and as soon as is practicable, of any significant changes from the operational implementation plans that may affect the joint meter reading area.

Community Action Partnership of Oregon (CAPO) and Oregon Energy Coordinators Associations (OECA) Conditions

Discussions between CAPO and PGE have identified several areas of potential impact upon PGE's low-income customers as a result of the implementation of AMI. Each of these areas is addressed below.

Remote Disconnect/Reconnect

Administrative Rules outline the specific communication requirements that PGE must meet in disconnecting and reconnecting a customer. CAPO and OECA want assurance that PGE's low-income customers understand the rules ahead of their application using AMI Remote Disconnect/Reconnect functionality so that they can proactively seek the assistance they need in paying their utility bills. To assist in educating customers, PGE will:

- In coordination with Community Action Agencies (CAAs), by December 15, 2008, prior to the start of full AMI meter deployment, develop the following training materials:

- Train the trainer materials that CAA personnel could use in their interaction with low income clients,
- General training information that could be provided to low income customers and social service agencies that serve these customers,
- Workshop material that could be delivered by either PGE or CAA personnel.
- Training of CAA representatives to assure their understanding of the need to communicate only completed and authorized commitments to PGE in relation to reconnections.
- Communicate with CAAs their responsibility in meeting contract obligations by providing funds to PGE within 45 days of the commitment date.

Development of this material will take into account the best methods of communication, including DVDs. During the Systems Acceptance Test consideration will be given to testing communications methodologies with low income customers associated with remote disconnect/reconnect.

During the development of these Administrative Rules, PGE outlined plans to assure that reconnections would be done in a timely manner. To assure reconnections are completed in a timely manner, PGE will:

- Where AMI meters with the automatic disconnect/reconnect feature are deployed, PGE will commit to provide same day reconnections when payments are processed at authorized payment locations or commitments are made by CAAs and reconnection requirements are met by 5:00 PM on Monday through Thursday, and by 3:00 PM on Fridays. PGE will establish procedures to facilitate the customer's required reapplication for service.

During the full deployment of meters across PGE's service territory as part of the AMI Project, PGE plans to install approximately 238,000 remote disconnect/reconnect meters in non-owner-occupied residences. Subsequent to the AMI Project deployment, PGE may consider deployment of additional remote disconnect/reconnect meters as part of the general meter replacement activities and not as a specific incremental cost to customers receiving those meters. However, no formal process has yet been defined about how that deployment would be implemented. Prior to implementing a post-AMI Project deployment of remote disconnect/reconnect meters, PGE will:

- Meet with CAPO, CAAs, OPUC Staff and other interested parties to review the implementation plan, provide sufficient time for review, and address identified concerns.

Leveraging Data

AMI provides for the collection and assembly of AMI interval data for customers that will enable PGE to deliver benefits described in the Information Driven Energy Savings (IDES) portion of this document. To assist CAAs and low-income customers in accessing electricity usage information to manage their electric bills, PGE will:

- As part of the IDES Project, make AMI interval data available and accessible to low income customers and, with customer approval and specific training (developed jointly by PGE and CAPO/CAAs), to CAAs that serve these customers. The timing of this commitment will be driven through the development of specific implementation plans as part of the IDES Project.

Long-Term Benefits of AMI Functionality

As part of demand response and appliance market transformation programs discussed earlier in this document, there is the potential for new technologies to be made available in the market place in the form of "smart" appliances and in-home communications devices providing pricing information. To assure that low-income customers are provided equivalent access to these new technologies, PGE will:

- Propose critical peak pricing demand response programs as voluntary "opt-in" programs.
- Provide educational information on demand response programs to PGE Customer Service Representatives and CAA representatives so that they can explain to low-income customers the potential risks of higher bills should they choose to participate in such programs but not reduce energy usage at critical times.
- Support local, regional and national policy decisions that would provide the opportunity for low-income customers to have access to "smart" appliances and in-home communications devices providing pricing information if/when they become available in the market. This will enable low-income customers to have the opportunity to use these technologies to lower their energy usage and their bill.

Limited Service Delivery

CAPO and CAAs have expressed an interest in exploring the possibility of providing minimal, lifeline-like electricity service to customers who have been "disconnected". Such a service could entail providing continuous operation of a refrigerator for the safety and stability of a household's perishable food and/or medications and the operation of, for example, a single standard household outlet. Because PGE is also interested in exploration of this possible service after completing the installation of the initial AMI system, PGE will:

- By March 31, 2009, enter into policy discussions with CAPO, CAAs and other interested parties about providing minimal, lifeline-like service to customers who have been "disconnected". Technology discussions will proceed by September 30, 2009 and PGE will assure that technology decisions made by PGE will not preclude the opportunity for consideration of this program.

Pre-Paid Electric Metering

Pre-paid metering is not a program or functionality that will be included as part of the AMI deployment project. While PGE has discussed using the AMI technology to pilot a pre-paid metering program, no decision to proceed has been made. To assure that this potential program is applied appropriately, PGE will:

- Prior to proposing a pre-paid metering pilot program to the OPUC, meet with OPUC Staff, CAAs, CUB, and other parties to explore parameters associated with pre-paid metering.

Status Reporting

To keep all parties informed of activity in addressing the CAPO OECA conditions, PGE will:

- Semi-annually, beginning in April of 2008 and throughout the deployment period, report to CAPO, CUB the OPUC Staff on status of the development and implementation of discussions, materials and trainings related to the low-income (CAPO) conditions.