BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180

In the Matter of	)
PORTLAND GENERAL ELECTRIC,	)
Request for a General Rate Revision.	)

RATE CASE TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

August 9, 2006

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Our names are Bob Jenks and Lowrey Brown, and our qualifications are listed in CUB Exhibits 101 and 102 respectively.

I. Introduction

We find this case notable both in the procedural complexities involved, and in the new procedural complexities proposed. This testimony addresses PGE's general rate case filing, though issues of power costs come up in context. CUB and ICNU are co-sponsoring a cost of capital witness, and that testimony will be filed next week. Though the prudence and costs of Port Westward are included in this case, the plant is not expected to come online until two months after UE 180 rates go into effect. As with any project, the risk of delay exists, and a delay would further distance the rates set in this rate case from the tariff established for Port Westward. Not only is the timing of the Company's filing a concern with regard to Port Westward, we are also unable to evaluate the prudence of the resource, as the Company has not demonstrated that its actions in pursuit of its action plan from LC 33 are in concert with the construction of Port Westward.

PGE's testimony demonstrates inappropriate risk-aversion, and the Company's proposals shift risk onto customers in a number of ways. Starting from a general rate case, the Company proposes a new annual update to replace its RVM, and on top of that, an annual power cost adjustment to capture any power cost variations from the update. Besides the procedural burden of layering mechanisms, the Company's proposal for an annual power cost adjustment is, yet again, unacceptable. Staff and the parties have spent countless hours working with PGE to develop an annual power cost adjustment mechanism, but the Company's inflexibility and its seeming indifference to Commission Orders have made this process fruitless. We demonstrate the unacceptability of PGE's proposed adjustment mechanism, and urge the Commission to adopt the mechanism we propose so that the parties can move beyond this debate.

PGE proposes a new advanced metering program in UE 180, asks the Commission to essentially pre-approve it, yet does not include this expense in its requested revenue requirement. The Company's business case for advanced metering is weak at best, and does not appear to have fully accounted for the work done by other utilities in analyzing the prospects of advanced metering infrastructure. Neither the Company nor Oregon regulation have evaluated which load control programs can reasonably be expected to succeed, and a business case without that understanding may be based on false assumptions. Finally, we object to the Company's plan to reduce the differential between blocks for residential customers' inverted block rate design.

II. Investor-Owned Utilities Are Paid A Return To Manage Risk

In PGE's presented case, the Company's approach to power costs and risk in general would drastically change Oregon's regulatory approach by reallocating nearly every risk to customers. This is not appropriate for an investor-owned utility that is paid a return on its regulated assets in exchange for managing risk.

A. Regulation, Risk & Rate Of Return

PGE's perception of a number of basic regulatory principles, at least as presented in the Company's testimony, is decidedly skewed. Before addressing PGE's proposal specifically, we find it necessary to first address the Company's redesigned regulatory framework.

i. Power Cost Variations Are Integral To Rates Based On A Future Test Year

We state again, as we have in so many cases recently, that the regulatory balance in setting rates based on a future test year lies in the inherent deviations of actual conditions from those that were forecast. There are a myriad of variables involved, and some will be greater than forecast, while others will be lower. In any given year, the net variation may result in the Company either over-collecting its revenue requirement or under-collecting it.

The Company goes to great length to describe how distressing and unreasonable these power cost variations are, and, in so doing, the Company provides a very nice description of how the system is supposed to work.

> We believe that, notwithstanding an annual update of forecast NVPC, a substantial probability remains that the actual incurred NVPC will differ significantly from the forecast most years and will do so in both a positive and negative manner, resulting in lower NVPC one year and higher NVPC another year.

UE 180 PGE/400/Lesh-Niman/33.

We may take issue with the suggestion of a "substantial probability" of power costs differing "significantly" from forecast, but otherwise, PGE's description sounds like Oregon ratemaking as it is supposed to work. To demonstrate how badly the balance in the regulatory paradigm is working, PGE presents a graph showing its power cost variances for 1993 through 2005, a 13-year period which includes both the Western Energy Crisis and its fallout. We approximated the values from the graph the Company provides which yields the following table:

Power Cost Variations

Year	'93	'94	'95	'96	'97	'98	'99	'00	'01	'02	'03	'04	'05	Total
Above	115					15					160	90	50	430
Below		-5	-50	-130	-20		-25	-100	-160	-45				-535

UE 180 PGE/400/Lesh-Niman/34.

Again, PGE's example is a nice demonstration of how power costs deviate above and below forecast over time. This data shows the Company enjoying a net of over $100 million in power cost variations over the period. Not only does this data include the Western Power Crisis and the following market and Company-specific turmoil, if you look back 12 years instead of 13, the Company comes out ahead by approximately $220 million in net power cost variations. It should also be noted that the Company's power costs have been rising throughout the period presented, so a $50 million variance is a much smaller percentage of power costs now than it was back in 1995, and the Company was coming out on top quite a bit in the early part of the period.[1]

This is not to suggest that no risk accompanies power cost variations, or that a utility should bear the entire brunt of those variations, regardless of magnitude, but that power cost variations are a normal and accepted part of forecasted ratemaking, and that a utility is expected to manage them and is allowed to benefit from them. At the risk of being redundant, following are two quotes we also include in our Power Cost Testimony in this case. They come from recent Commission Orders and describe the reasonable range of power cost variation the Company is expected to manage.

> In UM 995, for instance, we established a deadband around PacifiCorp's baseline of 250 basis points of return on equity. We allowed no recovery of costs or refunds to customers within that deadband, reasoning that the band represented risks assumed, or rewards gained, in the course of the utility business.

UM 1071 OPUC Order No. 04-108, page 9.

> To determine whether an event is extraordinary and has substantial financial impact, the Commission has, in prior cases, examined whether the event impacted the utility's earnings beyond a reasonable range within which the utility should bear the entire cost or benefit of variability.

UE 165/UM 1187 OPUC Order No. 05-1261, page 9.

The Commission, Staff, and the parties have expressed an openness to adopting a power cost adjustment mechanism for PGE, and have dedicated an inordinate amount of time working with the Company to design one. The Company, however, continues to refuse anything that is less generous than what it wants.

[1] The Company's testimony does not specify whether the dollar figures are real or nominal, so, for purposes of the table, we assumed they are nominal.

ii. Dollar-For-Dollar Recovery And Repayment Have Never Been The Goal

There seems to be an underlying presumption in PGE's testimony that ratemaking should match a utility's revenue and expense, dollar-for-dollar, on an annual basis.

> Thus, while to some extent [sharing] works – as a dead-band does – to preclude the utility from recovery of some level of prudently incurred cost…

UE 180 PGE/400/Lesh-Niman/36.

> The Commission stated that "unusual, but not necessarily extraordinary, events – should be used for hydro-related PCAs." Order No. 05-1261 … If this conclusion applied to a retrospective adjustment for comprehensive NVPC variances, it would suggest that there is some level of "usual" prudently incurred cost that a utility may not have an opportunity to recover.

UE 180 PGE/400/Lesh-Niman/44.

The above quotes from PGE's testimony suggest an underlying presumption that Oregon regulation strives to cover each specific utility cost to the dollar on an annual basis. This is absurd, never mind the parade of annual regulatory proceedings the Company is proposing in order to achieve this; a fundamental assumption of forward-looking ratemaking is that "there is some level of 'usual' prudently incurred cost that a utility may not have an opportunity to recover," in any given year. There is also the assumption that, in any given year, there is a level of additional profit a utility will have the opportunity to recover, and that, over time, under-recovery and over-recovery will approach a reasonable balance. We are troubled by what seems to us to be a subtext of assumed annual dollar-for-dollar recovery in the Company's approach to forecasted ratemaking.

iii. Uncertainty & Risk

We find the following quote from PGE's testimony indicative of the Company's mindset, and, therefore, disturbing:

> While utilities have traditionally borne responsibility for managing costs within their control, they have not borne responsibility for uncertainty.

UE 180 PGE/400/Lesh-Niman/44.

Uncertainty is unavoidable in life; the utility business is no exception. PGE is paid a return on equity in a large part to manage uncertainty and the risk that comes with it, and the Company is clearly in a better position to manage this risk than customers. If the Company would like a regulatory framework that eliminates uncertainty and risk, then its return on equity should be adjusted to that of Treasury Bills, about 5%.

B. Absolut Risk Aversion

In addition to our earlier discussions about PGE's unwillingness to include a deadband and the Company's attempt to rid itself of most, if not all, exposure to power cost variations, the following three examples serve to further paint a picture of a utility that is striving to dump as much risk as possible onto customers. Without a commensurate reduction in return on equity, this is not appropriate.

i. PGE Filed A Test Year Before Port Westward's Online Date

In its testimony, the Company argues that Port Westward should just be rolled into rates when it comes online because:

> … it makes more sense simply to "track" the plant into the already approved test year when it becomes available.

UE 180 PGE/400/Lesh-Niman/17.

As the date of the test year and Port Westward's online date are so close, it may seem sensible to wrap Port Westward into this rate case, but what would have made a lot more sense, as the dates are so close, would have been for the Company to wait that small amount of time and file the case for a test year that actually includes Port Westward. In being unwilling to wait two or three months to file, the Company created unnecessary controversy, procedural work, and analytic work for everyone involved.

However, it may not simply have been impatience that prompted the Company to file early. A utility may not charge customers for resources that are not used and useful, and this should mean that a significant capital project that is not used and useful on the date that rates go into effect must wait until the next rate case to be included in a utility's ratebase. We have a phrase for this: regulatory lag. By filing its case in the manner that it did, the Company eliminated the possibility for any regulatory lag associated with bringing Port Westward into ratebase.

Construction projects are always at risk of unexpected delays, so a test year starting at least a few months after a plant is scheduled to come online puts the utility in a better position to accurately project the start-up date, and gives both the utility and the parties some leeway for possible delays while the rate case is being processed. The time period between the plant's start-up and the utility's new rates going into effect is typical regulatory lag, which is part of the risk a utility is paid a return on equity to manage. However, by timing their filing such that rates would go into effect two months after Port Westward's scheduled online date, PGE is asking for rates to go into effect two months before, and in so doing shields itself from the risk of regulatory lag.

ii. PGE Does Not Include The Variable Cost Of Port Westward In The RVM

PGE not only eliminated any risk of regulatory lag on the front end, but the Company has also attempted to protect itself, at the expense of customers, on the back end. We address this issue in our Power Cost Testimony, but need to describe it here to demonstrate how the Company has attempted to shift risk onto customers wherever possible. For a fuller discussion of this issue, please see CUB/100/Jenks-Brown/7.

To calculate power costs for the period of time before Port Westward comes online, PGE ran MONET as if Port Westward did not exist and the Company simply purchased power on the spot market. So, until Port Westward comes online, customers will be paying an annualized cost that is based on spot market purchases replacing Port Westward. Port Westward, however, is expected to have a lower variable cost than the market, so we know that power costs with Port Westward will be lower than without.[2] Yet customers will be charged, for the time period before Port Westward comes online, on an annualized power cost value that we know is too high.

If Port Westward comes online as scheduled, rates will reflect costs including Port Westward. If Port Westward is delayed, customers will be paying rates that have already been calculated as if the Company were making last-minute market purchases to replace Port Westward's expected output. PGE is trying to shift the risk to customers both from regulatory lag, as well as from increased power costs should Port Westward be delayed.

iii. PGE Asserts Its Right To Collect 100% Of Boardman Outage

We address the specifics of this issue in our Power Cost Testimony, CUB/100/Jenks-Brown/1-7, but mention it again here to demonstrate PGE's attempt to get full recovery for the Boardman outage. Rather than accept the normal utility risk associated with plant operation, the Company has included the entirety of Boardman's outage in 2005 in the plant's forced outage rate.[3] PGE states that, once it knows how much recovery the Commission grants the Company in its Boardman deferral, it will

[2] UE 180 PGE/300/Quennoz-Shue/36.
[3] UE 180 PGE/400/Lesh-Niman/5.

remove a proportional time period from Boardman's forced outage rate. Of course, the deferral period goes into 2006, and the Company is asking for full recovery in the deferral period itself, so it is unclear how any deadband, sharing bands, or imprudence disallowances would figure into PGE's updated forced outage rate. In any event, the Company intends to recover the entirety of the Boardman outage one way or another.

C. PGE Is Not A Gas Utility

To support its cost-recovery argument, PGE relies heavily on the gas utilities' purchased gas adjustment mechanisms.[4] While some analogies can be drawn, there are important differences to consider when applying the purchased gas adjustment mechanism to an electric utility. A gas utility's ratebase consists primarily of pipes, the company's distribution plant. An electric utility's ratebase also includes the company's distribution plant, poles and wires. However, unlike a gas utility, an electric utility's ratebase includes far more than its distribution plant. An electric utility's distribution system represents only a portion of the company's ratebase, which also includes expensive generating plants.

Utilities only earn a profit on their ratebase. For a gas utility, that is its distribution plant. The purchased gas adjustment removes a gas utility's risk from the power supply (natural gas) portion of the company's costs, upon which it earns no profit. A power cost adjustment mechanism for an electric utility also removes risk associated with the utility's power supply function. The crucial difference, however, is that an electric utility is paid a profit on its generating plants, which are a critical part of its power supply function.

[4] *id.* at 38-40, 46.

Another significant difference is that, while a gas utility is simply a price-taker on the gas market (and the Commission allows the gas utility to pass that price through, barring imprudence), electric utilities have the responsibility and the opportunity to optimize resource decisions. The inexactitude of cost recovery is an integral part of the regulatory incentive for an electric utility to actively and prudently manage its power supply assets. If an electric utility performs well between rate cases, it can keep the benefit of the low costs; if the utility performs poorly, its financial performance will suffer accordingly.

III. PGE's GRC, APCU & APCV[5]

In this rate case, PGE has proposed a caravan of mechanisms by which the Company would like its rates set, updated, trued-up, and adjusted.

A. PGE's Proposed Caravan Of Mechanisms

In UE 180, PGE proposes to set its base rates with a general rate case, and then adjust those rates through a variety of mechanisms. The Company proposes replacing its annual power cost update, the RVM, with another annual power cost update, now to be called the Annual Power Cost Update (Annual Update). Layered on top of this, PGE proposes a power cost adjustment mechanism to be called the Annual Power Cost Variance (Annual Variance). The Company also discusses possible adjustments to annually true-up planned outages, and match the cost of planned outages with any performance improvement that maintenance brings.[6] All of this would be in addition to

[5] General Rate Case, Annual Power Cost Update, and Annual Power Cost Variance.
[6] UE 180 PGE/400/Lesh-Niman/1&29.

other regulatory proceedings such as deferrals, of which the Company currently has at least five.[7]

This layering of proposed mechanism upon proposed mechanism suggests that PGE is getting twisted in its own knickers. The problem with PGE's proposed parade of adjustment mechanisms stems from PGE's unrealistic desire – even expectation – for annual dollar-for-dollar recovery of power costs. This is simply not how forward-looking ratemaking is done in Oregon. The Commission has been clear that there is a certain level of power cost variation a utility is expected, and paid, to manage, and neither Staff nor the parties have ever indicated that such recovery, or anything close to it, is appropriate. In this testimony, we address some of the specifics of PGE's proposed mechanisms, but the Company's overall proposed mixture of mechanisms is built on a foundation of misguided principles, and so doesn't lend itself to Band-Aids or patches.

B. PGE's Proposed Annual Power Cost Update

PGE proposes to replace its current annual power cost update: the Resource Valuation Mechanism or RVM, with a new annual power cost update: the Annual Power Cost Update or Annual Update. Certainly, there are minor differences between the old and the new, but for all practical purposes, they are the same mechanism. In UE 180, PGE specifically includes forced outage rates, as, obviously, forced outage rates are on the Company's mind these days. On this particular topic, we very much hope that the Company is fighting the last war. The Company also calls out planned outages, an old sore from UE 172 where PGE proposed to collect twice for the same planned outage.[8] Acknowledging this problem, the Company puts forth a possible remedy involving yet

[7] UM 1234-Boardman, UM 1238-SB 408, UM 1256-Grid West, UM 1269-Stable Rate Tariff, & UM 1271-SB 408.
[8] UE 172 CUB/100/Jenks/2-5.

another annual true-up, whereby the difference between planned and actual maintenance outages might be spread over the following years. The Company also professes to be open to developing some sort of mechanism to include both the benefit, as well as the investment and O&M costs, of planned maintenance outages that improve a plant's performance.[9]

i. Modeling Changes

There has been considerable controversy in past RVMs, as the Company is well aware, about the inclusion of modeling updates in that annual update process. Staff and the parties have argued that modeling updates were inappropriate for the RVM process, we further put such a condition in the UE 149 stipulation, and STILL the Company persisted.[10] PGE's assertion "any model change or data input not on this list would not occur in the Annual Update process" is a dollar short and a day late.[11] Our understanding is that this was supposed to be the case for the original RVM, so this suggestion represents no improvement.

ii. The Timing Of The Proposed Annual Update

PGE proposes that its Annual Update be filed on July 1st (the RVM is filed in April), by October 1st the Company would finalize its load and planned outage forecasts, and by November 15th the Company would provide a final MONET run.[12] The upshot of this, is that the Company proposes to replace the RVM with a very very similar mechanism, but remove three months of process time which parties had used to examine the filing and pursue discovery. Given the controversy in UE 172 over the repeat planned

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[9] UE 180 PGE/400/Lesh-Niman/29.
[10] UE 172 CUB/100/Jenks/6-7.
[11] UE 180 PGE/400/Lesh-Niman/25.
[12] *id.* at 31.

outage at Sullivan, we are particularly sensitive to the proposition of receiving a finalized planned maintenance outage schedule in October, when the final filing is in November. As always, last minute contracts and prudence are also very much on our minds.

iii. Forward Price Curves

We appreciate the Company's proposal to use the average of five daily forward price curves, instead of just one, for its Annual Update. While this does mitigate the impact of a sudden, one-day spike, any sharp movement in that 5-day period would be concerning, and a significant move in a forward price curve might need to be addressed more specifically than simply rolling it into a 5-day average. In the interest of keeping parties abreast of the annual update process, it makes sense to include an automatic notification provision, should there be a material spread between the high and low curves in the 5-day period, or if the Company's 5-day average differs materially from the 5-day average of an independently produced curve, as the Company already validates its curve using externally-generated curves.[13] Under these circumstances, the Company should notify the Commission and the parties, so that, if necessary, the Commission can take timely action.

iv. Residential Customers & Annual Updates

CUB has expressed its dissatisfaction with PGE's RVM on numerous occasions, and, in UE 170, urged the Commission not to include residential customers in PacifiCorp's annual power cost adjustment.[14] These annual mechanisms are designed to facilitate direct access for industrial customers and prevent unwarranted cost-shifting,[15] and our position is that it is neither necessary nor appropriate to include residential

[13] *id.* at 30.
[14] UE 170 CUB/100/Jenks/30.
[15] UE 170 OPUC Order No. 1050, page 21.

customers in these processes, as residential customers are not eligible for direct access and do not benefit from it. We appreciate the Commission's acknowledgement of our concerns in its UE 170 Order, and urge the Commission to again consider the role of residential customers in an annual mechanism designed to capture costs for direct access.

PGE's RVM, in valuing the Company's resources for direct access, also serves to reduce the Company's risk of power cost variations between rate cases, because it allows the Company to annually update its forecast of variable power costs. Should the Commission decide to include customers not eligible for direct access in this annual mechanism, we ask the Commission to consider the relationship between this annual update mechanism and the Company's return on equity.

C. PGE's Proposed Annual Power Cost Variance

PGE's proposal for a power cost adjustment mechanism looks very much like the mechanisms we have seen proposed by the Company before, with little or no deadband, and little or no sharing. Last year PGE proposed a hydro-only adjustment with a small deadband and no sharing.[16] This year the Company proposes no deadband and little sharing. This is not acceptable, and CUB has been very clear about its position in testimony, settlement, and workshops.

i. Mechanism Must Have A Deadband

PGE does not want a deadband. The parties have indicated that this is a non-starter. The Commission has sanctioned a deadband, "reasoning that the band represent[s] risks assumed, or rewards gained, in the course of the utility business."[17]

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[16] UE 165 CUB/100/Jenks-Brown/2.
[17] UM 1071 OPUC Order No. 04-108, page 9.

Frankly, we are stunned by PGE's brazen disregard for the Commission's, Staff's, and the parties' judgment that a deadband is appropriate and necessary.[18]

a. PGE's No-Deadband Defense List

In PGE's testimony, the Company puts forth a list of why it does not put a deadband in its proposed mechanism. The Company claims that a deadband:

- Is not supported by precedent;
- Interferes with use of forced outage rates;
- Puts the Company at risk of factors beyond its control;
- Is not necessary to prevent rate volatility; and
- Is not necessary to allocate risk to a utility.

Precedent. There is a great deal of precedent for the use of a deadband in Oregon regulation: UE 137, UE 143, UE 165, UM 995, UM 1008/UM 1009, UM 1071, UM 1187.

Forced Outage Rates. Forced outage rates are a forecasting tool, they are not a tool for recovery of a specific incident. Yes, a plant's forced outage rate is based on the plant's past performance, but the forced outage rate is used to forecast expected, normalized conditions, not to recover costs from specific past outages. Instead, a rolling average of past performance is used so that, on average, over time, the performance of the Company's plants is reflected in rates. A hydro forecast is based on the weather's past performance, but it isn't intended to compensate for specific hydro years. PGE's claim twists forced outage rates from a forecasting tool into a retroactive recovery mechanism.

Risks Beyond PGE's Control. PGE does not specifically control hydro conditions; neither does the Company specifically control loads, market prices, or weather. It isn't expected to. The Company is expected to control its operations and

[18] UE 137, UE 143, UE 165, UM 995, UM 1008, UM 1009, UM 1071, UM 1187.

manage its assets in order to provide customers with a balance of safe, reliable, and reasonably-priced electricity. No, PGE is not expected to control nature or the market, but the Company ***is*** expected to react to whatever circumstances materialize, and to properly manage its resources within those circumstances.

Rate Volatility. The Company is proposing three different mechanisms with which to update rates annually. Given that a deadband would reduce the size of a surcharge or credit, it would decrease volatility. Certainly, there are other mechanisms to help reduce rate volatility, such as amortization schedule, but a deadband is simple and easy to administer.

Risk Allocation. The Company argues that a deadband is not necessary in order for a utility to bear risk. As quoted earlier, the sole example the Company provides of risk unrelated to the use of a deadband is administratively-determined prudence.[19] That being said, of course a utility bears risks unrelated to the use of a deadband. The Company's proposal includes load-neutralization to remove the effect of load variation in its proposed mechanism. Load will, of course, be different than forecast, and the risk that excess revenue collected and excess costs incurred, or vice versa, will not net to zero rests squarely with the utility, for better and for worse. PGE's suggestion that, because it bears other risks it should not bear this risk, has no basis.

b. A Deadband Plays A Central Role In Revenue Neutrality

CUB has pointed out in the past, that an asymmetric deadband and asymmetric sharing bands are important for revenue neutrality. When regional hydro conditions are poor, it puts upward pressure on power costs overall, and results in greater magnitude

[19] UE 180 PGE/400/Lesh-Niman/43.

power cost increases than the magnitude of power cost decreases when regional hydro conditions are good.[20]

More importantly for a mechanism designed to capture wide swings in power costs, when power costs rise there is no upper bound, whereas power costs can only drop as far as zero. A deadband and sharing bands must be asymmetric to recognize the asymmetry of the magnitudes of risk on either side of power costs. Thus, to ensure that a mechanism is revenue neutral between customers and the Company, the recovery bands for high power costs must be larger than the refund bands for low power costs in order to balance the magnitude of costs recovered and refunded over time. The Western Power Crisis is precisely the type of ultra-extraordinary event that can spike power costs, and that can be encompassed in an asymmetric deadband and sharing bands. Low power costs, on the other hand, do not have the potential to produce unbounded drops.

ii. Sharing

For its Annual Variance adjustment with no deadband, PGE proposes a sharing of 90% to customers and 10% to the Company:

- Variances shared 90% to customers and 10% to PGE
- Portion of variance related to changes in load from the forecast neutralized by comparing forecast average NVPC to actual average NVPC
- Prudence review

UE 180 PGE/400/Lesh-Niman/3.

In PGE's testimony in support of its proposed mechanism, the Company points out that, though it doesn't think sharing is appropriate at all, the token sharing it offers helps to align incentives.

[20] UE 165 CUB/100/Jenks-Brown/20.

> This alignment of interests allows an assumption that the utility is acting prudently. Thus, while to some extent this feature works – as a dead-band does – to preclude the utility from recovery of some level of prudently incurred cost, it serves a regulatory purpose of aligning interests on decision-making and easing regulatory burdens associated with establishing prudence.

UE 180 PGE/400/Lesh-Niman/36-37.

Interestingly, the above quote suggests that, by aligning interests, its proposed sharing "allows an assumption that the utility is acting prudently," yet, when touting its mechanism earlier in its Testimony, the Company offers a prudence review as one of the features of the mechanism. Is the Company proposing that its actions that would be captured by this mechanism be subject to a prudence review, or is the Company suggesting we should simply assume the Company's actions to be prudent?

Sharing is certainly an important component of a power cost adjustment mechanism, as it both balances risk and aligns incentives. We point the Commission to the sharing bands and percentages of our proposed mechanism.

IV. CUB's Recommended Power Cost Adjustment

In this testimony, we lay out CUB's recommended power cost adjustment, which looks to past dockets and past Commission Orders for guidance. We cannot bear the thought of addressing this issue in testimony again, and workshops with the Company have proven fruitless. We strongly recommend the Commission adopt CUB's recommended mechanism or something similar, and put this debate to rest.

A. PGE Is Deaf To The Commission, Staff & Other Parties

In our Power Cost Testimony in this case, we criticize the Company for its refusal to acknowledge Staff's and other parties demand for a reasonable deadband both for deferrals and power cost adjustment mechanisms.[21] We also denounce PGE's refusal to acknowledge the Commission's rulings in UM 1071 and UE 165/UM 1187. PGE seems to have wrapped itself in a blanket of intentional ignorance in order to pursue its vision of the perfect power cost adjustment. We thought we could not have been more frustrated than we were in UE 165/UM 1187, but we were mistaken.

PGE's unrealistic pursuit of its dream power cost adjustment has cost the Commission, Staff, and the parties a considerable amount of time, resources, and angst. Ironically, it has also cost its shareholders not only in regulatory ill-will and the distraction, time, and money spent on the Company's blind mission, but also in the money the Company would have saved had it been willing to compromise years ago. Most notably, PGE could easily have had a power cost adjustment mechanism in place when its Boardman plant went down last fall. No, the adjustment wouldn't have covered 100% of the cost of replacement power, but the mechanism would have covered the entire length of the outage, and timely recovery of a reasonable share of the costs would have been subject only to prudence.

B. CUB Proposes An Encompassing Annual Power Cost Adjustment

We propose the following simple, encompassing power cost adjustment mechanism, building on the principles explored most recently in UM 995, UM 1008, UM 1009, UM 1071, UM 1187, and UE 165. While the idea of a hydro-only adjustment mechanism has some appeal, we have yet to see a hydro-only mechanism that is simple, fair, and transparent. The interactions of variables in power costs are complex, and

[21] UE 180 CUB/100/Jenks-Brown/2-3.

designing a mechanism to untangle the impacts of hydro conditions from the impacts of other conditions appears difficult at best.

We rely in particular on UE 165, because, although it specifically addressed a hydro-only adjustment mechanism, the debate and the Commission's Order in that docket provide significant guidance on what is reasonable for an encompassing power cost adjustment mechanism.

i. An Encompassing Power Cost Adjustment Should Capture Extraordinary Conditions

Our experience through what proceedings leads us to the conclusion that an encompassing annual power cost adjustment mechanism should capture extraordinary conditions, but not simply unusual ones. For a single-component, hydro-only adjustment, the Commission chose a more-inclusive standard – "unusual," as opposed to "extraordinary" – as such a mechanism would pick up the fluctuations of a single variable, hydro conditions, and the Commission considers hydro availability largely beyond the Company's control.[22] An encompassing power cost adjustment, on the other hand, captures a multitude of variables, and those variables combine to create a wider range of normal conditions. Also, the number of components involved in the Company's power costs, and the ability of the Company to manage its resources in concert, suggest that the Commission's extraordinary standard is appropriate for an encompassing power cost adjustment.

ii. CUB's Proposed Mechanism

- Deadband and Sharing Bands: We started using a deadband with an upper bound equivalent to +250 basis points of return on equity, because of the Commission's use of 250 basis points in the past for exceptional events, and

[22] UE 165/UM 1187 OPUC Order No. 05-1261, page 9.

the Commission's confirmation that this represents a reasonable amount for a utility to absorb.[23] We selected asymmetric bands in an attempt to make the mechanism revenue neutral over time.[24] The sharing percentages come from the UM 1008 and UM 1009 deferrals.[25]

	Basis Points of ROE Equivalent		Sharing Customers - PGE
Deadband	above -125	below +250	0% - 0%
Inner Sharing Band	-200 to -125	+250 to +400	50% - 50%
Outer Sharing Band	below -200	above +400	90% - 10%

- Earnings Deadband: In its UE 165 Order, the Commission recommended an earnings deadband equivalent to +/- 100 basis points of return on equity. Though this was for a hydro-specific adjustment, it should be a reasonable place to start for an encompassing annual adjustment. "If earnings are outside this deadband, recovery or refund would be allowed to the perimeter of the range."[26]
- Amortization Cap: Currently, amortization of deferrals is limited to 6% of rates so as not to place undue hardship on customers. This is also important for a power cost adjustment mechanism, and we recommend the same 6% cap in general, but ask the Commission to consider extenuating circumstances such as an economic recession when amortization may need to be extended.
- A Prudence Review: A prudence review before amortization is an important regulatory check. The review would focus on whether the incurred power costs were part of a prudent response to conditions.

[23] "In UM 995, for instance, we established a deadband around PacifiCorp's baseline of 250 basis points of return on equity. We allowed no recovery of costs or refunds to customers within that deadband, reasoning that the band represented risks assumed, or rewards gained, in the course of utility business." UM 1071 OPUC Order No. 04-108, page 9. Footnote omitted.

[24] Despite PGE's aversion to a deadband in general, the Company has acknowledged the difference in regard to a deadband for single-variable, as opposed to encompassing, power cost adjustments: "PGE believes that it is reasonable to reduce the size of the dead band (relative to any dead band that may apply to a broad PCA) if the scope of a mechanism is reduced and does not include all power cost variances." UE 165 PGE/900/Lobdell-Niman-Tinker/17.

[25] UM 1008/UM 1009 OPUC Order No. 01-420, page 5.

[26] UE 165/UM 1187 OPUC Order No. 05-1261, page 9.

iii. A Deadband, Sharing Bands & SB 408

We recognize that the application of Senate Bill 408 may create a reason to reevaluate the appropriate magnitude of a deadband and sharing bands. In the past, a deadband and sharing bands were pre-tax values, and the utility then got a tax deduction, which reduced the impact of these bands. With the implementation of SB 408, these tax deductions will most likely be incorporated in the SB 408 automatic adjustment clause, and so no longer act to mitigate the amounts in a deadband and sharing bands. As the rules implementing SB 408 are not yet finalized, and as SB 408 is likely to face both a tough legislative session as well as legal challenges, we have designed a mechanism without taking into account SB 408. Once SB 408 is fully implemented, the Commission may wish to revisit a deadband or sharing bands such that the impact on the utility and the customers remains the same. CUB does not oppose redrawing the deadband and sharing bands so that post-SB 408 bands have the same after-tax impact as pre-SB 408 bands.

V. Port Westward

In this, the general rate case part of UE 180, PGE is asking the Commission to approve Port Westward's revenue requirement of $57 million, so that the Company can immediately add this to rates when Port Westward comes online. This is in contrast to how the plant is treated in the RVM part of UE 180, where the Company is asking the Commission to set rates without Port Westward, and assume that the 425 MW associated with Port Westward will come from spot market purchases. In the RVM, the Company is asking the Commission to ignore the cost savings associated with Port Westward when MONET models power costs for establishing 2007 rates. In the general rate case, it is asking for approval of the cost associated with ratebase and O&M, even though the plant is not expected to be used and useful until March. This is a decidedly one-sided approach to the inclusion of Port Westward in UE 180.

CUB has three major concerns regarding Port Westward. The first concerns Company's LC 33 Least Cost Plan, and how the Company is meeting its long-term power supply. The second concerns pre-approval of Port Westward, and what happens if Port Westward does not come online in March. The third concerns Port Westward's place among PGE's other resources, both supply- and demand-side.

A. PGE's Least-Cost Plan & Meeting The Utility's Long-Term Power Needs

We were a little surprised when we read PGE's testimony on Port Westward. In the Company's testimony on fixed power costs, PGE's introduction to its discussion of Port Westward contains the following statement:

> Commission Order No. 04-376 approved inclusion of Port Westward in the revenue requirement on a cost basis.

UE 180/PGE/300/Quennoz-Schue/35.

No, it did not. Commission Order No. 04-376 granted a waiver of OAR 860-038-0080(1)(b) which required that new resources be placed into rates at market. In that Order the Commission states:

> …we cannot make any decisions about whether to include the costs associated with Pt WW in rates, as those can only be made in a rate filing under ORS 757.205, *et seq.* In a future ratemaking docket regarding Pt WW, we will be looking carefully at PGE's assumptions and costs… Those decisions are, however, left for the future ratemaking proceedings.

LC 33 OPUC Order No. 04-376, page 4.

More importantly, on the same day that the Commission issued Order No. 04-376, it also issued Order 04-375 in which the Commission acknowledges 10 items in the Company’s action plan, and places three conditions on the acknowledgement:

> We acknowledge the plan filed by Portland General Electric Company (PGE) on March 26, 2004, with one exception and three conditions. First, we acknowledge the construction or acquisition of a high efficiency gas-fired resource, rather than the specific Port Westward plant. We also reserve the issue of whether this gas-fired resource will be included in rates at cost or market. As for conditions, we require three: 1) PGE must discuss constraints on competitive renewable development in the region with Staff, renewable developers, Bonneville Power Administration (BPA), the Energy Trust of Oregon (ETO) and other stakeholders; 2) PGE must include an action item in 2005 Integrated Resource Plan (IRP) to address how it will work with BPA and others to develop transmission capacity over the Cascades so that additional wind (and other) resources are accessible to PGE at a reasonable price; and 3) PGE must demonstrate that it has taken reasonable measures to acquire or option, as well as retain, cost effective transmission capacity over the Cascades before issuing its next Request For Proposal (RFP). Finally, we ask PGE to specifically address demand response program issues outlined in the order below, in its next IRP.

LC 33 OPUC Order No. 04-375, page 1.

In its testimony on Port Westward, PGE discusses why it chose Port Westward as the gas unit, and discusses why the execution of the Port Westward project was prudent. This is an inadequate case for the prudence of Port Westward.

The Company is relying on the Commission acknowledgement of a gas unit in LC 33 as the basis for the prudence of Port Westward. This is not appropriate. The Commission did not acknowledge a gas unit in a vacuum, the Commission acknowledged a 10-part action plan and put three conditions on the plan. While the Company lists the components of that action plan, it fails to report on the progress the Company is making in meeting these action items.

> The only new resource from the 2002 IRP Final Action Plan that is new since the 2006 RVM is Port Westward, commencing in March 2007.

UE 180 PGE/400/Lesh-Niman/57.

This is an important issue. PGE's integrated resource plan presents a series of actions that, taken together, seem to create a good balance between cost and risk. The Commission acknowledges an action plan that, taken together, seem to create a good balance between cost and risk. When evaluating the prudence of major, long-term resources it is important to review the action plan as a whole to see if the Company is acting in accordance with that plan.

PGE's discussion of the prudence of Port Westward fails to report on any items in the action plan, except the gas-fired resource, but the Commission did not acknowledge a gas-fired resource, it acknowledged a 10-point action plan with three conditions.

It is the Company's burden to show that Port Westward is prudent. Such a prudence review should begin with a review of the Company's action plan that was acknowledged in LC 33. PGE must provide the Commission and the parties with an analysis of Port Westward in the context of its action plan and the conditions that the Commission placed on it. This is not to suggest that PGE should blindly follow its action plan, regardless of whether conditions change, but the Company must explain what it has accomplished, and what has changed since the action plan was approved. Only with this knowledge can the prudence of Port Westward be determined.

B. The Timing Of Port Westward

CUB has expressed concern about the timing of this general rate case and the addition of Port Westward.[27] UE 180 will end before Port Westward is used and useful, and the rates resulting from UE 180 will go into effect before Port Westward is used and useful. PGE is using this docket to seek pre-approval of Port Westward so the Company can avoid any regulatory lag associated with including the resource in ratebase. While the timing of this rate case offers PGE protection, it creates a problem for customers. If Port Westward is delayed, a disconnect will result between the effective rates for calendar year 2007 and the used and usefulness of Port Westward. The Company's overall revenue requirement is established based on the sum of all the Company's costs and revenues. A delay in Port Westward would put that relationship between those cost and revenues out of kilter, and we provide a few conditions the Commission should consider to protect customers from any timing breach between Port Westward tariffs and rates established in UE 180.

PGE anticipates new rates effective in January, 2007, and currently estimates that Port Westward will become operational, and used and useful, on March 1, 2007.[28] This time gap, which is the source of the difference between the proposed revenue requirement and the inclusion in ratebase of a new resource (and, therefore, the need for regulatory gymnastics) is two months. The two-month gap is entirely a function of when PGE filed UE 180. Had PGE waited two months to file UE 180, our concerns would be somewhat diminished; had the Company waited four months they would be greatly diminished.

[27] See UE 184: CUB'S Respnse to PGE's Motion to Consolidate with Docket UE 180.
[28] UE 180 PGE/100/Piro-Lesh/7-8.

Port Westward is a $45 million addition to revenue requirement, almost a 3% increase.[29] The addition of Port Westward adds $279 million to PGE's ratebase, almost a 16% increase.[30] The traditional regulatory structure relies on the establishment of a revenue requirement based on an examination of total company costs in a test year. The test year is a set of forecast costs, plus known and measurable changes that would allow recovery of utility costs, plus a return on the Company's ratebase.[31]

There should be some discipline exercised as to the timing of rate cases in regard to the inclusion of new costs. In a rate case, as costs are examined, costs can be shown to have increased or decreased since the last rate case. Subsequent additions to a test year revenue requirement without a commensurate examination of the appropriateness of the overall revenue requirement, *i.e.* whether some declining costs have offset the need for an increase, is contrary to the concept of establishing *total* utility costs as the basis for rates. The longer the gap between a completed rate case and the inclusion of additional costs, the greater the deviation from a total utility cost-based revenue requirement.

The regulatory used-and-useful principle dictates that an investment intended to serve customers cannot be included in rates until it is shown that the investment is functioning and can be used to actually serve customers. Until such time as the investment is useful, ratepayers cannot be charged the costs associated with that investment. The manner to recover the costs of a new useful investment is through a general rate case process, where that cost can be examined with all other utility costs in establishing an overall revenue requirement. The cost of a new resource that has not been

[29] UE 180 PGE/200/Tooman-Tinker/27, PGE/201/Tooman-Tinker, and PGE Pretrial Brief, page 10.
[30] UE 180 PGE/210/Tooman-Tinker/1, and PGE Pretrial Brief, page 10.
[31] *The Economics of Regulation*, Kahn, Alfred, MIT Press, 1993, pages 26-57.

reviewed in a general rate case cannot be recovered before the next rate case and should not be recovered after the last rate case.

If a new investment is proposed to come online on a certain date shortly after a completed rate case, there is no assurance that the proposed start-up date will be met. If, in fact, the start-up date is delayed, then the new cost becomes increasingly disassociated from the overall revenue requirement, and theoretically, the Commission should begin its examination of costs all over again before it includes the cost of the new investment.

Traditional regulatory examination of costs and establishment of revenue requirement dictate that a new resource cost be reviewed along with other costs. PGE suggests that Port Westward will be used and useful only two months after the UE 180 rates go in effect. PGE suggests approval of tariffs that will bring Port Westward costs into rates when Port Westward comes online. There is no way to know as a certainty that Port Westward will come online two months after rates are in effect, or six or twelve months. That is why the better solution is to time the rate case in such a way as to make it more likely that a new resource is operating when the new rates go into effect. While the timing may never be perfect, we would avoid the case presented here, where we know that the resource will come on after rates are in effect, we just don't know how much later.

We saw this happen with NW Natural. A general rate case was used to pre-approve the ratebase associated with the Mist pipeline expansion and the Coos Bay distribution system, but those projects were delayed. The Coos Bay distribution system did not become used and useful until well after the test year associated with the rate case. We do not know whether other cost changes at NW Natural offset the cost increase associated with the Coos Bay distribution system. This is far from an optimal use of the ratemaking system.

PGE's last major plant addition had a similar problem. The Company attempted to get pre-approval for Coyote Springs in UE 88, a case associated with the closure of the Trojan nuclear power plant, but UE 88 ended months before Coyote Springs came online. Because costs fell and were well below the test year projections by the time Coyote Springs came online, it was apparent that the revenue requirement did not need to be increased in order to allow the Company recovery of Coyote Springs ratebase. The ratebase costs were offset by other declining costs.[32]

The Commission should not allow that to happen again. The Company is asking that the Commission pre-approve a significant asset that is not projected to be used and useful when these rates go into effect. If the project should be delayed, the Commission, Staff, and intervenors should have an opportunity to present evidence that other costs have changed, that the forecasted test period from this case no longer reflects the Company's costs, and that the revenue requirement increase necessary to allow the Company to recover and earn a return on Port Westward is different than what was determined in this case. The Commission can do this by placing the following three conditions on Port Westward rate recovery:

The first condition is that, as the Commission expects Port Westward to be used and useful early in this test period, that the tariff associated with Port Westward is only valid within 30 days of March 1, 2007.

The second condition is that, if Port Westward is not use and useful within 30 days, the Company must reopen UE 180. Staff and intervenors should be given a limited

[32] UE 93 CUB/1/Jenks/1-11.

period of time to review the Company's actual costs to determine whether there is new information that requires a reexamination of PGE costs before Port Westward is included in rates.

The third condition is that after six months, if Port Westward is not used and useful, the Company must file a new rate case in order to add the plant to ratebase. These conditions alleviate the problem of establishing a revenue requirement before the costs become legally recoverable and before the costs themselves are even relevant.

C. Prudence & Conservation

Port Westward, and other new supply resources, have to be evaluated on a least cost, least risk basis as part of a portfolio of actions taken by a utility.

> Acknowledgement of this Plan means that the Plan as a whole appears reasonable, based on the information and analysis available now. It also means that the specific resource actions, when combined with other action items, should result in "the mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs."

LC 33 OPUC Order No. 04-375, page 12.

It has become increasingly difficult to say whether an individual action is a prudent action to manage cost and risk, without examining the context of the other actions being taken by a utility to meet its expected load. For example, an increasing dependence on gas-fired generation may be viewed differently if it is accompanied by an increase in renewable power, conservation or some other action that reduces the impact of gas prices on customer rates.

What is currently missing from this evaluation of PGE rates, both in resource planning and in prudence reviews, is conservation. Beyond incorporating the energy efficiency benefits of existing Energy Trust of Oregon programs, we have not in this case considered whether more energy efficiency programs would be a lower cost, lower risk strategy of meeting the utility's load. In addition, we have not considered whether Oregon has the right mechanisms or incentives in place to acquire additional energy efficiency resources.

Oregon has a longstanding policy commitment to pursue all cost-effective electricity savings and avoid unnecessary expenditure on generation and grid additions. The Energy Trust's most recent assessment shows that current levels of energy efficiency investment will forfeit 210 average megawatts of inexpensive conservation by 2012.[33] We are falling short today, not because of any failings of the highly successful Energy Trust, but because we set the level of the Energy Trust funding in the 1990s when the projected cost of new resources was considerably lower. An NRDC analysis estimates that the California's PUC recently ramped-up savings targets are more than one percent of utilities' annual electricity sales;[34] the PGE service territory lags more than 40% below that level today, and our economy and environment are both losers as a result.

We need to evaluate what it will take to create the most prudent resource portfolio, one that is based on the lowest-cost, lowest-risk mix of both supply-side and demand-side resources. In the 1990s this discussion was often tied to a discussion of decoupling, and whether the utility has a disincentive to conservation that must be fixed before we can get the optimal level of efficiency investment.

Like most utilities, PGE recovers most of its fixed costs through the rates it charges per kilowatt-hour. In other words, a part of the cost of every kWh represents the

[33] Energy Trust of Oregon, Energy Efficiency and Conservation Measures Resource Assessment (May 2006) (evaluating achievable savings with a levelized cost below 5.5 cents per kWh).
[34] National Resource Defense Council. Chang, Audry. California's Sustainable Energy Policies Provide A Model For The Nation (March 2006), page 3.

system's fixed charges for existing plant and equipment, while the rest collects the variable cost of producing that kilowatt-hour. After approving a fixed-cost revenue requirement, the Commission sets rates based on assumptions about annual kilowatt-hour sales. If sales lag below those assumptions, the company will not recover its approved fixed-cost revenue requirement. By contrast, if the company were successful in promoting consumption increases above regulators' expectations and the incremental power it acquired to meet that load had a variable cost that was less than retail rates, its shareholders would earn a windfall in the form of cost recovery that exceeded the approved revenue requirement. And whether consumption ends up above or below regulators' expectations, every reduction in sales from efficiency improvements yields a corresponding reduction in cost recovery, to the detriment of shareholders.

We do not believe that it is appropriate to solve this problem by recovering all or most fixed costs in the form of fixed charges. This would require radical changes in rate design, would shift costs onto low-use customers who are not putting much of a burden on the need for new resources, and would dramatically reduce customers' rewards for saving energy at the very time they should be encouraged to conserve more. We would make a bad situation worse by reducing customers' rewards for conserving electricity, which is precisely what would happen if the Company shifted costs from volumetric to fixed charges.

In the 1990s we attempted to address this problem for electric utilities through decoupling: the use of modest, regular true-ups in rates to ensure that any fixed costs recovered in kilowatt-hour charges are not held hostage to sales volumes. Note that the true-up can go in either direction, depending on whether actual retail sales are above or below regulators' initial expectations. Unfortunately, due to decreases in the wholesale market and the fear of creating stranded costs as the industry looked to restructuring and/or deregulation, utilities reduced their investments in energy efficiency programs and there were no apparent benefits from the implementation of decoupling. Based on this experience we looked to the Energy Trust as a model that would ensure that a cost-effective level of energy efficiency would be acquired. This model has worked quite well, but with higher costs associated with new power supply, the Energy Trust's funding level is not achieving all the cost-effective conservation that is available.

More recently, on the natural gas side, we have been able to tie new energy efficiency funding for the Energy Trust with decoupling. An independent evaluation of NW Natural's decoupling program concluded in March 2005 that the mechanism was "effective in altering Northwest Natural's incentives to promote energy efficiency" and should be retained, although the authors recommended removing some rather complex features that were not relevant to the mechanism's primary purpose.[35] The Commission adopted an Order in August 2005 with a stipulation that simplified the mechanism and extended it for another four years.[36] One of the State's other major gas distributors, Cascade Natural Gas, secured its own decoupling mechanism recently when the Oregon Commission approved its May 18, 2006 tariff filing.[37]

The prudence evaluation of Port Westward provides the Commission an opportunity to explore whether the prudence of new utility resource actions should include an analysis of both supply-side and demand-side resources, and whether

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[35] D. Hansen & S. Braithwait, A Review of Distribution Margin Normalization as Approved by the Oregon Public Utilities Commission for Northwest Natural (March 2005), pages 67-68.
[36] UG 163 OPUC Order No. 05-934.
[37] The filing, numbered CNG/O05-10-01, was approved by the Commission on May 23, 2006

mechanisms that include decoupling directly tied to additional energy efficiency investment should be considered on the electric side.

We are not suggesting that PGE or any other electric utility should duplicate the work of the Energy Trust as Oregon's primary energy-efficiency delivery mechanism. For purposes of increased energy efficiency investment and results, utilities can work with the Energy Trust, rather than displacing or duplicating Energy Trust responsibilities.

We do recognize that it simply makes little sense to evaluate the prudence of a single new, large power plant, without determining whether that investment is part of an overall least-cost, least-risk portfolio.

VI. Advanced Metering Infrastructure

PGE is sort-of asking the Commission to increase rates by an additional $3.7 million, above the revenue requirement the Company filed for in this case, by approving the Company's Advanced Metering Infrastructure. They ask that the Commission find that the decision to proceed with advanced metering is "reasonable and prudent" at this time. If the Commission does not find it "reasonable and prudent" the Company will not proceed at this time.[38]

A. PGE Requests Additional Rate Hike To Install Advanced Metering

This is a little bizarre. PGE did not add this cost into their rate filing. When they noticed customers of the pending rate request, advanced metering costs were not included in that notice. The Company's analysis of the costs of advanced metering are disconnected from this case (for example, the analysis assumes the cost of capital from UE 115, not what the Company is seeking in this case). Utilities often ask for additional

[38] UE 180 PGE/800/Hawke-Carpenter-Tooman/3.

revenue requirement for new programs, but to do so without including the costs in revenue requirement is very unusual. The reason seems to be that PGE will not proceed with full advanced metering deployment without Commission approval.[39]

At this point, the Company projects the total cost to be $141 million, but the cost data is based on an initial projection, not actual bids. PGE cites "confidential budgetary quotes provided by vendors," as the basis of its cost information.[40]

The Company has issued a RFP for all of the "field equipment and the software" associated with AMI, but those results are not yet available.[41] In addition, the Company plans a "significant review by the Information Technology organization to estimate the cost of supporting the AMI projects."[42] This means that the cost information in the filing is a preliminary estimate, not actual bidding results.

Essentially the Company is providing some preliminary cost information to the Commission about a project that is a long way from being used and useful and asking the Commission to determine whether it is prudent and whether the program should be implemented. If the Commission says "yes," then later when this is used and useful and added to ratebase, the Company will be able to rely on the Commission's decision in this case to say "We did not even include it in our rate filing, but the Commission believed it to be prudent and ordered us to implement it."

Even with a strong business case for advanced metering, such a request would be difficult to grant. Putting that aside, an examination of PGE's business case does not support approval of advanced metering for the Company.

[39] *id.* at 9.
[40] *id.* at 4.
[41] *id.* at 6.
[42] *id.* at 9.

In this section we will examine PGE's business case, which fails to support deployment of advanced metering. In fact, we believe the current evidence shows that advanced metering will not provide a benefit. We will look at the failure of PGE's current advanced metering program, a program that the Company is proposing to abandon while charging customers million of dollars in stranded costs. We will examine some of the experiences other utilities have had with advanced metering. Finally, we will propose a deliberative process that we think the Commission should consider for examining the benefits of advanced metering. This would allow PGE to implement such a program at a later date, should it make a business case for such a program.

B. PGE's Business Case Suggests Advanced Metering Is Not Cost Effective

PGE claims that the net present value of all AMI-related costs and savings will reflect a benefit between $4 million and $20 million over the next 20 years depending on what happens with the joint meter reading program with NW Natural. If NW Natural abandons the joint meter reading program, to continue manual meter reading PGE would have to hire an additional 21 new meter readers. Under this scenario, advanced metering would save $20 million. If, on the other hand NW Natural does not abandon the joint meter reading program, the benefit will be approximately $4 million. According to PGE, it "is attempting to determine but is currently uncertain as to NWN's decision" regarding maintaining the existing joint meter reading.[43]

To understand NW Natural's decision, all you have to do is ask NW Natural (and we have done so in person and in a data request), and the Company will tell you that it has no plans to abandon joint meter reading with PGE. To do so would cost NW Natural

[43] *id.* at 15-16.

customers more than $4.6 million in new capital costs plus an additional annual O&M increase of $1.6 million. CUB Exhibit 201.

This means that there is no basis to claim that the advanced metering will save customers $20 million because that assumes actions on the part of NW Natural that it is not considering. In addition, it means that the claims of a benefit to PGE customers of $4 million cannot be claimed, because many of these customers are also customers of NW Natural and the advanced metering will require NW Natural to incur one-time costs of $4.6 million and annual costs of $1.6 million.

In other words, the best case reading of PGE's business case is that it will lead to a rate increase for NW Natural customers that is significantly larger that the savings PGE will receive. In addition, PGE's case was filed without the Company able to make a determination as to NW Natural's intention to continue joint meter reading. Because determining NW Natural's intention was an easy thing to do, it raises the question of how diligent PGE's case is and how much weight the Commission can give to it.

C. PGE's Business Case So Thin, That Small Changes Yield Negative Benefit

Even if one were to focus solely on the PGE costs and ignore the effects on NW Natural's customers, PGE's business case is so thin, it is hard to conclude from it that advanced metering is a wise investment. The net present value benefit of $4 million over 20 years is a small benefit from an investment of more than $140 million. But PGE's case uses projections for meter costs, installment cost and O&M savings. Small changes in these projected numbers could easily turn the projection into a negative number.

CUB increased the meter costs by 5% in 2007, 2008, and 2009, the years when the bulk of the meters are purchased, while making no other changes in the program.

This small change led to the value changing from a $4.4 million net benefit to a $1.6 million net harm. CUB Exhibit 202.

D. Here We Go Again, Shades Of UE 115

This is not our first experience with advanced metering and PGE. In the Company's last general rate case, UE 115, PGE also claimed that advanced metering, then called NMR or AMR, would benefit its system and customers and proposed to begin the process of converting PGE to advanced metering. At that time customers were facing rate hikes of 30% to 50% and CUB practically begged the Company to put off discretionary expenditures. PGE was not deterred and argued for advanced metering which resulted in a Commission Order that concluded:

> PGE has showed that postponing these programs will not lead to decreased costs, and may actually increase costs over time

OPUC Order No. 01-777, page 11.

The experience, however, has not been what was claimed in that case. PGE has significantly cut back from the advanced metering program that was ordered in UE 115.

In its filing PGE claims this was because "we found that direct access did not proceed as rapidly as anticipated and the technology did not develop as expected."[44] In answer to a data request the Company added that "our primary vendor suffered business failure and we installed a second-choice system." CUB Exhibit 203. Now, in this filing the Company proposes abandoning meters that were purchased as part of that program, and instead embark on a whole new round of purchasing new advanced meters. As part of its proposal in this case, PGE proposes accelerated depreciation of "existing" meters.[45] However, more than $5 million of this depreciation is actually new meters that were

[44] *id.* at 9.
[45] *id.* at 7.

purchased as part of PGE's advanced metering program that was launched after the Company's last rate case. CUB Exhibit 204. PGE should be more careful this time; we should all be more careful.

In addition, we recommend that the Commission not grant accelerated depreciation of any current advanced metering equipment. While the Commission did approve advanced metering in UE 115, PGE has failed to demonstrate that advanced metering continued to be a prudent course, especially in light of its chosen vendor's "business failure" and having to install a "second-choice system." The Company has also not demonstrated that accelerated depreciation is now a prudent course. In fact, nowhere in its testimony does PGE even discuss the need to replace millions of dollars in advanced metering equipment that the Company has already purchased.

E. Other Utilities' Experience With Advanced Metering

PGE cites examples of other utilities that have implemented advanced metering, but provides little discussion of their experience. Some of this experience is important. PGE cites San Diego Gas & Electric and Pacific Gas & Electric as examples of utilities that are pursuing advanced metering. However, we show that both of these utilities claim that advanced metering is not cost effective without time-of-use pricing. PGE's claim that the business case for advanced metering shows that it is beneficial without load control is contradicted by the experience of these California utilities. PGE also cites the example of Puget Sound Energy.[46]

Puget implemented advanced metering to facilitate the move to time-of-use pricing. Time-of-use pricing was so unpopular that the Washington Utilities and

[46] *id.* at 2.

Transportation Commission abandoned the program, and returned to traditional rate structures. CUB Exhibit 205. These examples should encourage us to be cautious, to investigate load control programs, and to be realistic about what programs are likely to be accepted here in Oregon before we embark on this path.

i. California

California took a thoughtful approach to advanced metering. The California Public Utility Commission first led an investigation into advanced metering, including load control programs. This led the California Commission to issue an Order telling the utilities what functionality and programs needed to be supported by advanced metering so the utilities' business case analyses could be based on real, expected programs. CUB Exhibit 206.

As California did, we should consider what we want to do with advanced metering, so the utilities' business cases can be based on the programs and program design that stand the greatest likelihood of succeeding. The California Commission provided utilities with six functions that would go into the utilities' business cases. Included in these six functions were opt-out time-of-use pricing plans for all classes of customers. We know from our experience with NW Natural's WARM program that opt-out programs (as opposed to opt-in) create a backlash.

In 2005, SB 441 passed the California Senate on a vote of 23-12. SB 441 prohibits the California Commission from requiring advanced metering for residential and small business customers until the Commission first evaluates the following:

1. The effect on average annual electricity rates for residential and small commercial customer classes for every year of repayment for the advanced metering investment.

2. The bill impacts of any proposed mandatory time-differentiated rates on residential customers in hot climate zones.
3. The amount of peak load reduction contrasted with other demand reduction program alternatives.
4. The *feasibility and* cost effectiveness of partial deployment in selected zones contrasted with deployment throughout an entire service territory of an electrical corporation.

CUB Exhibit 207. California SB 441. Emphasis theirs.

This does not surprise us. When the Oregon PUC considered mandatory measured telephone service in the 1980s, it led to passage of a ballot measure prohibiting it. The marketplace tells us that customers want simplicity in pricing. Long distance telephone calls used to be based on time-of-use pricing but once long distance became a competitive service, plans have largely moved away from time-of-use pricing. Making time-of-use optional through an opt-out (as opposed to an opt-in) will likely do little to make customers more responsive. In fact, our experience with the WARM program suggests that customers will see the opt-out as an attempt to trick them into taking something that they probably would not want.

ii. Pacific Gas & Electric

The business cases provided by the utilities included the avoided cost value associated with time-of-use pricing. In PG&E's business case, savings from meter reading, O&M, and other costs only support 89% of the cost of advanced metering. The other 11% comes from time-of-use and other load control programs that are not part of the business case that PGE has presented to us. In addition, the PG&E order specifically deals with what the Commission will do if the cost is more than projected. It will require the Company to absorb a percentage of costs above the projected costs up to a cap which limits recovery. CUB Exhibit 208.

iii. Southern California Edison

Southern California Edison was not cited by PGE. It responded to California's order by investigating the business case for advanced metering and concluded:

> Southern California Edison Company (SCE) has completed an extremely rigorous business case analysis of Advanced Metering Infrastructure (AMI). SCE's finding indicate that an integrated AMI solution that leverages additional commercially-available technologies has the potential to provide an effective platform for enhancing routine customer services, providing more sophisticated alternatives for load management and demand response, and increasing operational efficiencies and benefits. However, these enabling technologies have yet to be cost-effectively packaged or integrated into a streamlined meter for application in the United States. Therefore, SCE has concluded that given its operational starting point, an investment in currently-available AMI technology is not cost effective for SCE's customers. Instead, SCE proposes to achieve significant increased operational and demand response benefits through a concerted and aggressive effort to develop and "advanced integrated meter" (AIM that integrate additional technologies into the next generation of meters…
>
> …SCE envisions completing full deployment of the new AIM system no later than one to two years after the time that full deployment of today's AMI technology could be completed. SCE's customers would nevertheless be advantaged, despite this slight delay, given the superior attributes of the proposed AIM technology, including more durability, versatility and the ability to deliver significant improvement ins system reliability, customer billing and service options, outage management and operational efficiencies. Thus, it is critical that SCE's ultimate investment in AMI focus on "getting it right" instead of rushing to "get it done"

CUB Exhibit 209. Executive Summary, SCE Testimony.

iv. San Diego Gas & Electric

SDG&E's business case concluded that without mandatory time-of-use rates, deployment of advanced metering may not be justified. According to SDG&E witness Edward Fong:

> Operational benefits from AMI alone do not justify full or partial deployment of AMI. The combination of demand response benefits (*i.e.,* capacity and energy) and operational benefits are required to justify AMI deployment.

CUB Exhibit 210. Testimony of Edward Fong, page 1-2.

SDG&E makes clear that in order to justify advanced metering, time-of-use rates must not be voluntary:

> A necessary condition for AMI to achieve sufficient and significant demand response benefits is the simultaneous deployment of dynamic rates. Without dynamic rates, customers would have little incentive to reduce demand during critical peak periods. Voluntary demand response programs alone are insufficient to achieve the 5% demand response targets established in this proceeding and restate in the Energy Action Plan."

CUB Exhibit 210 Testimony of Edward Fong, page 2-9.

In addition, SDG&E proposes several off-ramps: conditions under which advanced metering deployment will not be cost-effective and will be suspended, including the following:

> 1) Dynamic rates are not adopted by the Commission for all customers that will achieve the equivalent demand response impacts set forth in this application.
> 2) Customer opt-out rates from default dynamic rates after the first year (2007) of deployment appear to exceed 40%.
> 3) Deployment or installation price points for residential customers (meters, communications hardware, installation labor costs) exceed estimated price points contained in the business case by 20%.
> 4) Software development costs for AMI meter data management systems appear to be exceeding business case estimates by 50%
> 5) Recovery of existing meters.

CUB Exhibit 210 Testimony of Edward Fong, pages 14-16.

In reading the business case testimony of California utilities, it is clear that Oregon may not be ready to make this leap. PGE's testimony on advanced metering is 13 pages long, whereas California utilities filed business case testimony that runs hundreds of pages. The California utilities have all concluded that without time-of-use pricing, advanced metering is not cost effective. The California Commission has already determined that it will allow time-of-use pricing under as an opt-out program. The California utilities and Commission are concerned with the possibility that costs will be above what is projected. In the case of PG&E the California Commission has already determined how to deal with cost overruns. In the case of SDG&E, the utility has asked the Commission to allow it to discontinue the program if costs go beyond certain levels.

v. Puget Sound Energy

PGE also cites the example of Puget Sound Energy which installed AMI and implemented a Time-of-Use pilot program in response to the power crisis. The PSE program was controversial. In 2002, the UTC allowed participating customers to opt-out of the program and ordered that the remaining customers be charged an additional $1.00 per month in an attempt to make the advanced metering cost effective. Eventually, after determining that 94% of customers paid higher rates under the plan than they would under standard rates, the WUTC canceled the program and returned customers to standard non-time-of-use tariffs. CUB Exhibit 205.

F. CUB Recommendation

Three things are clear from our analysis of advanced metering:

- PGE has failed to make a business case for advanced metering. The record does not support the conclusion that advanced metering will provide a net benefit to customers.
- This is not surprising, since the business case does not include load control measures, and other utilities have found that load control programs are necessary to make advanced metering cost effective.
- As compared to California, which seriously examined what to do with advanced metering before asking utilities to provide business case analysis and directed its utilities to do significantly more rigorous analysis that PGE,

> Oregon is not yet ready to decide what role of advanced metering and load control programs should play.

SCE found that existing meters do not provide the proper functionality. Earlier this year, Jesse Berst of SmartGridNews predicted that prices for advanced meters will drop by 50% by 2009. CUB Exhibit 211. In its UE 115 Order, the Commission determined that not going ahead with advanced metering immediately would lead to higher costs. Instead it led to millions in stranded costs. The current evidence suggest that the benefit of waiting and being thoughtful about advanced metering might well be lower costs. In light of this, CUB recommends that the Commission reject the Company's proposal in this case, and instead the do the following:

1. Open an investigation into Load Control Programs; and
2. Invite the utility to file an advanced metering proposal outside of a general rate case, after Oregon decides what load control programs are likely to be adopted and the Company can produce a business case based on those programs.

i. Open An Investigation Into Load Control Programs

This should happen first, before spending more than $100 million on advanced metering, not after the money is spent. If the experience of California utilities is found to apply to Oregon, PGE's business case is wrong and time-of-use pricing is necessary to make advanced metering cost effective. If we spend the money first, then there will be tremendous pressure to implement time-of-use pricing in order to justify the expense. CUB believes that mandatory or opt-out time-of-use will create a backlash and might not be a sustainable policy. We saw how these programs played with Puget customers, and we will see how they play in California. We should first determine what we want to do with time-of-use pricing and other load control programs before embarking down this road. That will allow us to build a business case around what Oregon actually expects to do with advanced metering. In PGE's last Least Cost Plan, the Commission ordered PGE to examine these programs in its next least-cost planning process. PGE, however, plans to invest in advanced metering before conducting this analysis, rather than doing the analysis first.

ii. Invite PGE To File An AMI Proposal Outside Of A General Rate Case

While PGE has proposed advanced metering in this and in its previous general rate case, UE 115, there is no good reason why advanced metering must be tied to a general rate case. In this case the Company is not adding anything to ratebase, they are seeking accelerated depreciation of existing meters and deferral of costs associated with the new meters. These two types of filing can proceed independently of a rate case. This means that after there is a review of load control programs and a business case built around what is expected in Oregon, the Company can proceed if the business case supports it.

VII. Rate Design

We are concerned both with the Company's suggestion that the residential customer basic service charge should be higher, and its proposal to eliminate an inverted block rate structure for the energy charge and reduce the block differential of the sum of the energy charge and the Bonneville credit by half, with an eye on eliminating the differential entirely.

A. Basic Meter Charge

PGE is proposing to keep the residential basic service charge, or meter charge, at $10. We agree with the Company that it is important to keep this charge low "in order to mitigate bill impacts to lower usage customers."[47] A more universal concern we have about a high meter charge is the disincentive it provides for conservation. The higher the percentage of customers' bills that is represented by the meter charge, the less incentive customers have to streamline their energy consumption, and conservation is becoming increasingly important.

PGE's $10 meter charge is higher than PacifiCorp's meter charge. PGE's high meter charge was set in UE 115, when the Commission established an inverted block rate structure, to prevent low-use customers from seeing a rate reduction while other customers were receiving almost a 30% rate hike.[48]

B. Block Rates & The Bonneville Residential Exchange

Along with keeping a utility's meter charge low to encourage conservation, an inverted block structure is another rate design tool that supports conservation. The Company proposes eliminating an inverted block rate structure from the energy charge, because PGE will not be receiving power from Bonneville.[49] The Company also claims that there is no cost basis for inverted block rate design in Schedule 102, Regional Power Act Exchange Credit (Residential Exchange).

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[47] UE 180 PGE/1300/Kuns-Cody/8.
[48] UE 115 OPUC Order No. 01-777 page 22. "In making this decision, we clarify that we adopt the proposed increase in the basic or customer charge based on reasons cited by CUB. The increase will avoid a rate decrease to low use customers while overall rates are increasing."
[49] UE 180 PGE/1300/Kuns-Cody/9.

> In order to mitigate the price effects on smaller usage customers we reluctantly propose to maintain the energy blocking nature of the design for Schedule 102 only. Currently the sum of the Energy Charge plus the Schedule 102 adjustment yields a price differential of 25 mills per kWh. We propose to reduce this block differential by half, to 12.50 mills per kWh. Eventually, we hope to eliminate the energy blocking because we believe that it has no cost basis.

UE 180 PGE/1300/Kuns-Cody/23.

We disagree with PGE; the Pacific Northwest has a wonderful, low-cost hydro system that keeps the average cost of power below that of the incremental cost of new resources. When a customer installs an air conditioner, that new load will cost the system, not the average cost, but the incremental cost. When a customer installs an energy efficient appliance, the reduction in load saves the system incremental cost, not average cost. A pricing structure that distributes historical low-priced hydro in the lowest usage block, and thereby prices customer changes in energy usage at the higher block, better reflects actual costs than does average pricing.

We are troubled by PGE's resistance to block rates for residential customers through the Residential Exchange for an additional reason of equity. The Residential Exchange was established to ensure that all residents of the Pacific Northwest receive an equitable share of the Northwest federal hydro resources. Putting aside the battle to defend investor-owned utility customers' right to an equitable share of those benefits, PGE's proposal to reduce, and then eliminate, the block nature of the Residential Exchange benefit, also brings up equity concerns. The benefit of the federal hydro system should go to the residents of the Northwest in equal proportion. So, too, PGE's allotted Residential Exchange benefit should go equally to every residential customer.

The Company's proposal to reduce and then eliminate the block structure of the rate design for the Residential Exchange means that customers who use more electricity will receive more of the benefit of the federal hydro system than customers who use less. No only does this provide a lousy conservation incentive, it is also unfair. Obviously, no per kWh rate design will ensure that each PGE residential customer receives the exact same value from the Residential Exchange, but keeping the Residential Exchange benefit in the first energy block at least shoots for this goal.

If, as PGE proposes, the Residential Exchange benefit is spread equally through all levels of usage, a customer with heavy electricity consumption will receive more of the Residential Exchange benefit than a customer with modest electricity consumption. This means that the amount of benefit a customer would receive would depend on the customer's income, lifestyle, and commitment to conservation. That would be a bit like parents dividing the inheritance between their children based on which child carried the most debt, so that the child who was frugal would receive less, and the child who was extravagant would receive more. It is neither fair, nor rational.

We recommend that the Commission require the Company to maintain its current inverted rate block structure both in the size of the blocks and in the rate differential between the blocks.

VIII. Conclusion

CUB recommends that the Commission:

Power Cost Adjustment

- Reject PGE's proposed Annual Variance mechanism; and
- Adopt CUB's proposed Power Cost Adjustment mechanism with its proposals for deadbands and sharing bands, an earnings deadband, an amortization cap, and a prudence review.

Port Westward

- Find that PGE has failed to demonstrate that Port Westward costs were prudently incurred because the Company has failed to offer any evidence that it is prudent within the context of the Commission-approved LCP action plan and conditions the Commission put on that action plan;
- If PGE demonstrates prudence, the Commission should find that the Port Westward tariff is only valid within 30 days after March 1, 2007;
- If Port Westward is not use and useful within 30 days after March 1st, the Commission should require PGE to reopen UE 180 to allow parties an opportunity to review PGE's updated costs;
- If Port Westward is not used and useful within 6 months of March 1st, the Commission should require PGE to file a new rate case in order to place the plant into rate base; and
- Indicate the role that conservation should play in evaluating the prudence of future resources.

Advanced Metering

- Find that PGE's business case for Advanced Metering Infrastructure does not demonstrate that such an investment is reasonable and prudent;
- Deny accelerated depreciation of AMI costs that have been incurred since UE 115;
- Open an investigation into load control programs; and
- Invite PGE to file an advanced metering proposal outside of a general rate case if it can establish a strong business case, after Oregon decides the role that load control programs will play in the business case.

Rate Design

- Require PGE to maintain the current inverted rate block structure both in the size of the blocks and the rate differential between the blocks.

Rates and Regulatory Affairs
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June 1, 2006

Public Utility Commission of Oregon
550 Capitol Street, N.E., Suite 215
P.O. Box 2148
Salem, Oregon 97308-2148

Attn: Vikie Bailey-Goggins
Administrator, Regulatory Operations Division

RE: Docket UE 180; Staff Request No. 1-5

NW Natural submits the following response to Staff's request for information in the above-referenced matter.

1. Please estimate the additional costs NW Natural would expect to incur within its joint meter reading area with Portland General Electric (PGE) if PGE installs advanced metering infrastructure (AMI) as outlined in Docket UE 180 (PGE/800). Please include the assumptions NW Natural makes in determining these estimates, as well as supporting workpapers showing the cost components with formulae and cells intact.

   NW Natural Response: The incremental capital expenditure required to provide meter reading within the joint meter reading area is estimated to be $4,594,818. The incremental O&M would ramp up to an estimated annual total of $1,565,000 in 2009. The attached file "NWN JMR 0530.xls" provides the assumptions and calculations for these estimates.

2. Please describe the action(s) NW Natural would take in the short run as well as in the long run to address gas meter reading within the joint meter reading area if PGE installs its proposed AMI system. For example, would NW Natural expect to install an advanced metering (drive-by/walk-by) system in the joint meter reading area within the next five years, 10 years or 20 years if PGE installs its proposed AMI system?

   NW Natural Response: NW Natural would conduct a financial analysis to determine whether a traditional or automatic meter reading solution is the most cost effective solution to serve the joint meter reading area. Should it be shown that automatic meter reading is the best solution, it is expected that this would be installed within the next five years.

Public Utility Commission of Oregon, UE-180
June 1, 2006
Page 2

3. Please describe the action(s) NW Natural would take in the short run as well as in the long run to address gas meter reading within the joint meter reading area if PGE does *not* install its proposed AMI system. For example, would NW Natural continue joint meter reading as it is practiced today so long as PGE does not install an AMI system? Or would NW Natural consider installing an advanced metering (drive-by/walk-by) system in the joint meter reading area within the next five years, 10 years or 20 years, even if PGE did not install AMI?

   NW Natural Response: Should PGE decide not to install its proposed AMI system, in the short run NW Natural would continue with joint meter reading. NW Natural would conduct a financial analysis to determine whether a traditional or automatic meter reading solution best serves the joint meter reading area for the long term.

4. Has NW Natural determined whether there is a positive business case for installing an advanced metering system to read gas meters in the joint meter reading area? For example, has the Company performed a Total Resource Cost analysis to determine ratepayer benefits (reduced revenue requirements)? If the Company has performed such an analysis, please provide the assumptions used in the analysis and workpapers with cells and formulae intact.

   NW Natural Response: NW Natural has not performed a revenue requirement analysis for an automatic metering system to read gas meters in the joint meter reading area. A preliminary analysis indicated that installation of a gas AMR system in the joint meter reading area would not be economic as long as the joint meter reading program continued in that area.

5. Please provide an update on the Company's installation of an advanced metering system outside of the joint meter reading area, including:

   NW Natural Response:

   a. Project start date
      May 2006

   b. Estimated project completion date
      April 2007

   c. Number of meters already converted/replaced
      None

   d. Number of remaining meters to convert/replace
      232,676

   e. Estimated total project costs
      $15,300,000

f. Estimated annual savings
Estimated annual savings ramp up to a level of $2,275,000 (real dollars) in 2008 exclusive of growth.

g. Net present value (in dollars) of investment
$1,144,484

Please call if you have questions.

Sincerely,

NW NATURAL

C. Alex Miller, Director
Regulatory Affairs & Forecasting

cc: Stephanie Andrus

PGE Net Present Value (Staff DR 374, attachment C)		**(4,434,000)**
PGE Meter cost (Staff DR 374, attachment C)		
	2007	24,310,368
	2008	64,723,331
	2009	30,948,791
PGE Meter cost plus 5%		
	2007	25,525,887
	2008	67,959,498
	2009	32,496,231
PGE Net Present Value (Staff DR 374, attachment C with increased meter costs)		**1,561,000**

July 7, 2006

TO: Jason Eisdorfer
CUB

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to CUB Data Request
Dated June 22, 2006
Question No. 008

Request:

Please provide all studies, analysis, and other written material that PGE relied upon when it made the decision to abandon the UE 115 NMR/AMR program and instead launch a different AMR program.

Response:

As described in PGE's response to CUB Data Request No. 003, part b, PGE did not fully implement the NMR system envisioned in UE 115. Instead, our primary NMR vendor suffered business failure and we installed a second-choice system to meet the requirements of SB1149. This system is more costly and less functional than the systems available today. After evaluating the NMR industry for over five years, we prepared a cost-effective solution to PGE's Board of Directors in August 2005. For this analysis, see PGE's responses to OPUC Data Request No 374 (provided in response to CUB Data Request No. 009). For a more detailed discussion of why PGE will replace specific meters, see PGE's responses to OPUC Data Request Nos. 506-509 (provided as Attachment 008-A).

July 7, 2006

TO: Jason Eisdorfer
CUB

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to CUB Data Request
Dated June 22, 2006
Question No. 007

Request:

What is the total amount of capital expenditure of the NMR/AMR that would be included in the accelerated depreciation associated with the UE 180 AMR program?

Response:

Attachment 007-A provides NMR detail by asset type, including net plant and the amount that would be included in accelerated depreciation associated with the UE 180 AMI program. Please note that Attachment 007-A does not include approximately $950,000 for meter or network purchases from the Metering Technology Corp. according to Commission Order 03-518 (Docket UI-216).

Depreciation for Network Meter Reading
1999 -2004 Vintages

37000 Job 19731 Purchase Meters

Year	Closed to Plant	Accum Depreciation	Net Plant
1999	$ 1,048,157	$ 492,604	$ 555,553
2000	(142,222)	(63,215)	$ (79,007)
2001	468,354	195,249	$ 273,105
2002	299,443	108,869	$ 190,574
2003	60,011	17,784	$ 42,227
	$ 1,733,743	$ 751,291	$ 982,452

Percent Not Retained with AMI 100.0%
Amount for Accelerated Depr. $ 982,452

37000 Job 20293 Purchase Meters

Year	Closed to Plant	Accum Depreciation	Net Plant
1999	$ -	$ -	$ -
2000	-	-	$ -
2001	3,199,156	1,333,677	$ 1,865,479
2002	1,462,978	531,899	$ 931,079
2003	101,725	30,146	$ 71,579
	$ 4,763,859	$ 1,895,722	$ 2,868,137

Percent Not Retained with AMI Approx 80%
Amount for Accelerated Depr. $ 2,294,509

37000 Job 21888 Purchase Meters

Year	Closed to Plant	Accum Depreciation	Net Plant
2000	$ -	$ -	$ -
2001	-	-	$ -
2002	-	-	$ -
2003	104,479	30,962	$ 73,517
2004	119,987	26,639	$ 93,348
	$ 224,466	$ 57,601	$ 166,865

Percent Not Retained with AMI 90.0%
Amount for Accelerated Depr. $ 150,179

30300 Job 19732 Data Store Software

Year	Closed to Plant	Accum Depreciation	Net Plant
1999	$ -	$ -	$ -
2000	-	-	-
2001	2,686,802	2,686,802	-
2002	-	-	-
2003	-	-	-
	$ 2,686,802	$ 2,686,802	$ -

Percent Not Retained with AMI 100.0%
Amount for Accelerated Depr. $ -

30300 Job 20870 Meter Data App. Host Software

Year	Closed to Plant	Accum Depreciation	Net Plant
1999	$ -	$ -	$ -
2000	-	-	-
2001	-	-	-
2002	4,276,307	3,421,046	855,261
2003	-	-	-
	$ 4,276,307	$ 3,421,046	$ 855,261

Percent Not Retained with AMI 0.0%
Amount for Accelerated Depr. $ -

39102 Job 20673 Data Store Hardware

Year	Closed to Plant	Accum Depreciation	Net Plant
1999	$ -	$ -	$ -
2000	618,702	503,953	114,749
2001	148	116	32
2002	-	-	-
2003	-	-	-
	$ 618,850	$ 504,069	$ 114,781

Percent Not Retained with AMI 100.0%
Amount for Accelerated Depr. $ 114,781

39102 Job 20953 Meter Data App. Hardware

Year	Closed to Plant	Accum Depreciation	Net Plant
1999	$ -	$ -	$ -
2000	-	-	-
2001	338,576	264,720	73,856
2002	46,985	33,738	13,247
2003	-	-	-
	$ 385,561	$ 298,458	$ 87,103

Percent Not Retained with AMI 0.0%
Amount for Accelerated Depr. $ -

39102 Job 22035 Meter Data App. Hardware

Year	Closed to Plant	Accum Depreciation	Net Plant
1999	$ -	$ -	$ -
2000	-	-	-
2001	-	-	-
2002	-	-	-
2003	60,048	37,669	22,379
	$ 60,048	$ 37,669	$ 22,379

Percent Not Retained with AMI 100.0%
Amount for Accelerated Depr. $ 22,379

39703 Jobs 19734, 21705-8, 21886-7 Network

Year	Closed to Plant	Accum Depreciation	Net Plant
1999	$ -	$ -	$ -
2000	-	-	-
2001	-	-	-
2002	496,921	162,990	333,931
2003	899,547	238,621	660,926
2004	757,280	147,540	609,740
	$ 2,153,748	$ 549,151	$ 1,604,597

Percent Not Retained with AMI 100.0%
Amount for Accelerated Depr. $ 1,604,597

Total All Jobs

Total Cap Ex.	**$ 16,903,384**	Excluding $951,384 for MTC meters and network capital
Total Accum Depr	**$ 10,201,808**	
Net Plant	**$ 6,701,576**	
Amount for Accelerated Depr.	**$ 5,168,897**	

[Service Date November 15, 2002]

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	DOCKET NO. UE-011570 and UG-011571 (consolidated)
Complainant,	)	FOURTEENTH SUPPLEMENTAL ORDER: GRANTING APPLICATION TO AMEND TWELFTH SUPPLEMENTAL ORDER
v.	)	
PUGET SOUND ENERGY, INC.,	)	
Respondent.	)	
. . . .	)	
In the Matter of the Requested Waiver of Statutory Notice in Connection with the Tariff Revisions Filed by	)	DOCKET NO. UE-021447
	)	ORDER GRANTING LESS THAN STATUTORY NOTICE AND WAIVER OF WAC 480-100-194
Puget Sound Energy	)	

1 **PROCEEDINGS.** On November 26, 2001, Puget Sound Energy, Inc. ("PSE" or the "Company") filed tariff revisions designed to effectuate a general rate increase for electric and gas services. On December 3, 2001, PSE filed a request for an interim electric rate increase. These proceedings were consolidated under Docket Nos. UE-011570 and UG-011571. The Commission established procedural schedules for an interim phase (electric) hearing and general rate phase (electric and gas) hearing.

2 On June 20, 2002, the Commission approved the multi-party settlement stipulation of disputed electric and common issues in PSE's pending general rate case, Docket Nos. UE-011570 and UG-011571 in its Twelfth Supplemental Order: Rejecting Tariff Filing; Approving and Adopting Settlement Stipulation dated June 20, 2002 ("Order").

3 On November 6, 2002, PSE filed its Application for Amendment of Rate Case Order Provisions Regarding Time-of-Use (TOU) Rates. Also on November 6, 2002, Puget Sound Energy (PSE) filed with the Commission revisions to its currently effective Tariff WN U-60, designated as Third Revised Sheet No. 307, First Revised Sheet No. 308, First Revised Sheet No. 309, and Second Revised Sheet No. 324. The purpose

of the filing is to accelerate the termination date of PSE's Time-of-Use (TOU) rates, so that the current TOU pilot program will end November 18, 2002 rather than in September 2003.

4 **PARTIES.** Markham Quehrn and Kirstin Dodge, Perkins Coie LLP, Bellevue, Washington, represent Puget Sound Energy, Inc. John A. Cameron and Traci Kirkpatrick, Davis Wright Tremaine, represent AT&T Wireless and the Seattle Times Company. Danielle Dixon, Policy Associate, Northwest Energy Coalition, represents that organization and the Natural Resources Defense Council. Carol S. Arnold, Preston Gates Ellis, Seattle, Washington, represents Cost Management Services, Inc., and the cities of Auburn, Des Moines, Federal Way, Redmond, Renton, SeaTac, Tukwila, Bellevue, Maple Valley, and Burien ("Auburn, *et al.*"). Ron Roseman, attorney at law, Seattle, Washington, represents the Multi-Service Center, the Opportunity Council, and the Energy Project; Charles M. Eberdt, Manager, Energy Project also entered his appearance for the Energy Project; Dini Duclos, CEO, Multi-Service Center, also entered an appearance for that organization. Angela L. Olsen, Assistant City Attorney, McGavick Graves, Tacoma, Washington, represents the City of Bremerton. Donald C. Woodworth, Deputy Prosecuting Attorney, Seattle, Washington, represents King County. Melinda Davison and S. Bradley Van Cleve, Davison Van Cleve, P.C., Portland, Oregon, represent Industrial Customers of Northwest Utilities. Elaine L. Spencer and Michael Tobiason, Graham & Dunn, Seattle, Washington, represent Seattle Steam Company. Edward A. Finklea, Energy Advocates, LLP, represents the Northwest Industrial Gas Users. Donald Brookhyser, Alcantar & Kahl, Portland, Oregon, represents the Cogeneration Coalition of Washington. Michael L. Charneski, Attorney at Law, Woodinville, Washington, represents the City of Kent. Norman J. Furuta, Associate Counsel, Department of the Navy, represents the Federal Executive Agencies ("FEA"). Michael L. Kurtz, Boehm, Kurtz & Lowry, Cincinnati, Ohio, represents Kroger Company. Kirk H. Gibson and Lisa F. Rackner, Ater Wynne LLP, Portland, Oregon, represent WorldCom, Inc. Elizabeth Thomas, Preston Gates Ellis LLP, Seattle, Washington, represents Sound Transit. Harvard M. Spigal and Heather L. Grossman, Preston Gates and Ellis LLP, Portland, Oregon, represent Microsoft Corporation. Simon ffitch, Assistant Attorney General, Seattle, Washington, represents the Public Counsel Section, Office of Attorney General. Robert D. Cedarbaum, Senior Assistant

Attorney General, and Shannon Smith, Assistant Attorney General, Olympia, Washington, represent the Commission's regulatory staff (Staff). [1]

5 **COMMISSION:** The Commission grants PSE's Application for Amendment of Rate Case Order Provisions Regarding Time-of-Use (TOU) Rates. The Commission grants the requested waiver of statutory notice in connection with the tariff revisions filed by PSE on November 6, 2002, and authorizes the tariff revisions to become effective on November 18, 2002. The Commission grants the requested waiver of the customer notice provisions of WAC 480-100-194.

MEMORANDUM

6 On June 20, 2002, the Commission approved the multi-party settlement stipulation of disputed electric and common issues in PSE's pending general rate case, Docket Nos. UE-011570 and UG-011571 in its Twelfth Supplemental Order: Rejecting Tariff Filing; Approving and Adopting Settlement Stipulation dated June 20, 2002 ("Order"). The Order approved and incorporated by reference Exhibit E, Settlement Terms for Time of Use (TOU). Exhibit E provided that

> [PSE's] current pilot time of use (TOU) program for small consumers (residential and Schedule 24) shall be extended to September 30, 2003, to permit creation of a collaborative and to conduct a thorough evaluation of the program.

Order, Ex. E, § B.2.[2]

7 Customers were permitted to opt out of the TOU program, but customers remaining on the program were required to pay an additional $1.00 per month beginning July 1, 2002, to help pay for the incremental meter reading and data handling costs of the program. An additional $0.16/customer/month was to be recovered through higher kwh charges in the TOU rate schedules. *Id.* at §§ D.4.-5. The TOU rate differential was also adjusted. *Id.* at § E.8.

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[1] In formal proceedings, such as this case, the Commission's regulatory staff (Staff) functions as an independent party with the same rights, privileges, and responsibilities as any other party to the proceeding. There is an "*ex parte* wall" separating the Commissioners, the presiding ALJ, and the Commissioners' policy and accounting advisors from all parties, including Staff. *RCW 34.05.455.*

[2] The pilot program for large customers (Schedules 25, 26, 31) ended on October 1, 2002. *See* Order, Ex. E, § H.14.

8 The Order required PSE to notify continuing participants in the program if their participation in the program was not cost effective for one or more months in a given quarter. Such notice was to provide a comparison of the customer's bill under TOU to what the customer's bill would have been under the applicable flat rate for all months during the quarter. The first quarterly information was to measure the third quarter of 2002, with notice sent to customers beginning no later than thirty days after October 1, 2002. Order, Ex. E, § F.9.

9 The Order further provides that at the end of the extended TOU pilot program, no later than September 30, 2003, customers are to default to service under the equivalent non-TOU tariff schedule applicable to them "[u]nless the customer requests to remain on the TOU rate schedule regardless of the personal economic consequences." Order, Ex. E, § G.13.

10 Exhibit E of the Order also approved a TOU collaborative process to explore issues including the cost-effectiveness and conservation impact of TOU programs. Order, Ex. E, § I.15. The Commission's Order further required that the TOU collaborative present it with four progress reports regarding the collaborative's work, beginning on November 1, 2002, and ending with a Final Report and Recommendation by July 1, 2003. Order at ¶ 34. The TOU pilot program remains an important source of information to the Commission. The Commission, for example, is keenly interested in learning whether the combination of conservation and peak shaving by customers on TOU rates resulted in lower average electricity bills than would have resulted had those customers remained on flat electricity rates. This order does not alter the analysis requirements or reporting schedule included paragraph 34 of the 12th Supplemental Order. The Commission, however, may later amend the reporting requirements to reflect changed circumstances.

11 The TOU collaborative began its work pursuant to the Order. On November 1, 2002, PSE filed the required Study Design report. Collaborative participants have raised serious questions about the cost-effectiveness of TOU rates as currently configured.

12 PSE has also recently provided the requisite notice regarding the bill impacts of the program for individual customers. In conducting its analysis for such notice, PSE determined that only six percent (6%) of customers remaining on the TOU program were paying less for their electric power than if they were taking service under the

equivalent non-TOU tariff schedule. PSE determined that ninety-four percent (94%) of customers remaining on the TOU program were paying higher electric bills than they would have paid if they had opted out of the program. On average, customers paid $0.80 more per month than they would have if they were not on the TOU program, although some customers paid several dollars more because of their continued participation in the program.

13 Because nearly all of its current TOU customers are paying more under the program than they would if they were not on the program, PSE seeks through its Application and the proposed revised tariff sheets to end the TOU pilot program early, and to move remaining TOU customers to the equivalent non-TOU tariff schedule applicable to them.

14 To accomplish this change, PSE proposes that the expiration date for TOU rates that is set forth in the Order, Exhibit E, Sections B.2., E.8, and G.13 be amended from September 30, 2003 to November 18, 2002, and that PSE be ordered to default current TOU customers to the equivalent non-TOU tariff schedule applicable to them as of the termination of the TOU tariff schedules.

15 The Commission has authority to amend its Order as requested pursuant to RCW 80.04.210 and WAC 480-09-815. PSE has provided notice of its Application to the parties who executed the Settlement Terms for Time of Use (TOU), Exhibit E to the Order, and to all parties to the general rate case, Docket Nos. UE-011570 and UG-011571.

16 The Commission also has authority to approve the requested termination date, which provides for less than thirty-day notice, pursuant to RCW 80.28.060 and 480-80-122. PSE requests that the Commission approve the earlier termination date because doing so will reduce the bills of most of the customers who are currently taking service under the TOU tariff schedules. PSE also requests that the Commission exempt the proposed revision of the TOU tariff schedules from the notice requirements of WAC 480-100-194, pursuant to WAC 480-100-008, because such exemption is consistent with the public interest, the purposes of the underlying regulation, and applicable statutes. PSE proposes to provide notice to customers of the termination of the TOU schedules through billing inserts sent out after the Commission's approval of the termination.

17 On November 6, 2002, Puget Sound Energy (PSE) filed with the Commission revisions to its currently effective Tariff WN U-60, designated as Third Revised Sheet No. 307, First Revised Sheet No. 308, First Revised Sheet No. 309, and Second Revised Sheet No. 324. The purpose of the filing is to accelerate the termination date of PSE's Time-of-Use (TOU) rates, so that the current TOU pilot program will end November 18, 2002 rather than in September 2003. PSE also requests a waiver of the customer notice provisions of WAC 480-100-194. PSE again proposes to notify customers of the elimination of the time-of-use rates through bill inserts sent after Commission approval of the application.

18 WAC 480-80-121 requires thirty days' notice prior to the effective date of the tariff. The tariff sheets bear an inserted effective date of December 7, 2002. This date recognizes statutory notice as required. The Company requests, however, that statutory notice be waived as authorized in WAC 480-80-122, and that the revisions become effective November 18, 2002. Since the proposed tariff revisions are found to be fair, just, and reasonable, and waiver of statutory notice is consistent with the public interest, it is appropriate that the Commission grant the waivers PSE requests with an effective date of November 18, 2002.

FINDINGS OF FACT

19 Having discussed above all matters material to our decision, and having stated general findings, the Commission now makes the following summary findings of fact. Those portions of the preceding discussion that include findings pertaining to the Commission's ultimate decisions are incorporated by this reference.

20 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including electric companies.

21 (2) Puget Sound Energy, Inc., is a "public service company" and an "electrical company" as those terms are defined in RCW 80.04.010, and as those terms otherwise may be used in Title 80 RCW. Puget Sound Energy, Inc., is

engaged in Washington State in the business of supplying utility services and commodities to the public for compensation.

22 (3) PSE's time-of-use rates no longer are fair, just, and reasonable.

23 (4) PSE's tariff filing of November 6, 2002, in Advice No. 2002-26, is in the public interest and produces results that are fair, just, and reasonable.

CONCLUSIONS OF LAW

24 Having discussed above in detail all matters material to our decision, and having stated general findings and conclusions, the Commission now makes the following summary conclusions of law. Those portions of the preceding detailed discussion that state conclusions pertaining to the Commission's ultimate decisions are incorporated by this reference.

25 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings. *Title 80 RCW.*

26 (2) The Commission's prior orders in Docket Nos. UE-011570/UG-011571, and in any related proceedings discussed in the body of this Order, should be amended to the extent necessary, or rescinded to the extent required, to effectuate the provisions of this Order. *RCW 80.04.210; WAC 480-09-815*.

27 (3) The proposed tariff revisions to PSE's WN U-60 Tariff G – (Electric Tariff), Third Revised Sheet No. 307, First Revised Sheet No. 308, Original Sheet No. 309, and Second Revised Sheet No. 324, should become effective on November 18, 2002.

28 (4) The Commission should grant PSE's request to waive the provisions of WAC 480-100-194.

29 (5) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order. *Title 80 RCW.*

ORDER

30 (1) THE COMMISSION ORDERS That PSE's Application for Amendment of Rate Case Order Provisions Regarding Time-of-Use (TOU) Rates is granted. The expiration date for TOU rates that is set forth in the Commission's Twelfth Supplemental Order, Exhibit E, Sections B.2., E.8, and G.13 is amended from September 30, 2003, to November 18, 2002, and that PSE is ordered to default current TOU customers to the equivalent non-TOU tariff schedule applicable to them as of the termination of the TOU tariff schedules.

31 (2) THE COMMISSION ORDERS FURTHER That PSE's requested waiver of statutory notice in connection with the tariff revisions it filed on November 6, 2002, is granted and the tariff revisions shall become effective on November 18, 2002.

32 (3) THE COMMISSION ORDERS FURTHER That it retains jurisdiction over the subject matter and the parties to effectuate the provisions of this Order.

DATED at Olympia, Washington, and effective this 15th day of November 2002.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

MARILYN SHOWALTER, Chairwoman

RICHARD HEMSTAD, Commissioner

PATRICK J. OSHIE, Commissioner

MP1/MLC/hl2 2/19/2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing.	Rulemaking 02-06-001 (Filed June 6, 2002)

JOINT ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S RULING PROVIDING GUIDANCE FOR THE ADVANCED METERING INFRASTRUCTURE BUSINESS CASE ANALYSIS

1. Summary

This ruling provides policy direction regarding the minimum level of system functionality that should be supported by an advanced metering infrastructure (AMI) for purposes of analyzing full-scale AMI deployment. The ruling also addresses which customer classes should be included in the AMI analysis, clarifies the costs to be included in the base case AMI analysis, directs the Working Group 3 (WG3) moderator to schedule a workshop to review sources of avoided costs for valuing peak demand reductions, seeks input on the need for a workshop on methodologies for estimating demand response, and clarifies the meaning of "out of scope" impacts.

2. Background

The purpose of this proceeding is to increase the level of demand response, in particular price responsive demand, "as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment."[1] California's energy agencies have already provided some guidance on the types of rates and technologies to be supported by the AMI system in the vision statement appended to Decision 03-06-032 as Attachment A. The rate options and technology functionalities outlined in the vision statement can be utilized as the framework for the AMI system functionality and business case analysis.[2]

3. Guidance on AMI System Functionality

Agency staff from the California Energy Commission (CEC) and this Commission report that participants at the January 28, 2004 AMI workshop requested additional direction on the types of rate structures the AMI system should support and more specificity on the functional requirements of the full scale AMI system for purposes of developing the AMI business cases. Agency staff report that the AMI system functionality requirements are driven by the type of rate structures and programs the system is expected to support.

The purpose of an AMI system is to provide the metering and communications capability to economically support a wide variety of rate and associated customer service options. The ideal AMI system will maximize the amount of demand response that can be achieved cost effectively. We do not know *a priori* the particular mix of rates, programs, and customer service functions that will meet this cost effective ideal. Thus it makes sense to analyze an AMI system that supports a wide variety of potential rate structures and

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[1] Ruling 02-06-001, p. 1.

[2] Key bullets related to AMI business case are reprinted as Appendix A of this ruling.

customer service options that the Commission may approve over the useful life of the AMI system.

As indicated in the original rulemaking, we prefer to take a broad view of the investigation of AMI. The Commission can always authorize a narrower scope AMI system implementation if warranted, but it is more difficult to expand functionality if it has not been considered in the business case analysis. Therefore, the AMI system analyzed should support the following six functions:

a. Implementation of the following price responsive tariffs[3] for:
   (1) Residential and Small Commercial Customers (200kW) on an opt out basis:
      (a) Two or Three Period Time-of-Use (TOU) rates with ability to change TOU period length;
      (b) Critical Peak Pricing with fixed (day ahead) notification (CPP- F);
      (c) Critical Peak Pricing with variable or hourly notification (CPP-V) rates;
      (d) Flat/inverted tier rates.
   (2) Large Customers (200 kW to 1 MW) on an opt out basis:
      (a) Critical Peak Pricing with fixed or variable notification;
      (b) Time-of-Use;
      (c) Two part hourly Real-Time Pricing.
   (3) Very large customers (over 1 MW) on an opt out basis:

[3] The costs of developing an AMI system capable of supporting a variety of rate designs and customer service applications must be separated from the actual costs associated with implementing a specific new tariff. If a party chooses to estimate the benefits of a particular dynamic rate in its AMI analysis, the benefits and the costs of implementing that rate (such as customer education or billing changes) should be separated from core costs of developing and installing AMI hardware, software, and communications systems.

(a) Two part hourly Real-Time Pricing;

(b) Critical Peak Pricing with fixed or variable notification;

(c) Time-of-Use Pricing.

b. Collection of usage data at a level of detail (interval data) that supports customer understanding of hourly usage patterns and how those usage patterns relate to energy costs.

c. Customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs.

d. Compatible with applications that utilize collected data to provide customer education and energy management information, customized billing, and support improved complaint resolution.

e. Compatible with utility system applications that promote and enhance system operating efficiency and improve service reliability, such as remote meter reading, outage management, reduction of theft and diversion, improved forecasting, workforce management, etc.

f. Capable of interfacing with load control communication technology.

We recognize that there may be additional levels of "system" functionality or technical requirements that need to be specified by the utility and other parties to ensure accurate cost comparisons between different AMI systems. These may relate to the frequency of meter polling, scalability of IT infrastructure, the amount of data storage in meters versus other collection points in the network, and communications systems needed to support these functions. These specifications are best handled by the experts and we urge the "functionality" subcommittee set up by WG3 to develop a matrix that includes any additional specifications necessary to implement the policy direction above.

4. Customer Classes to be Included in the AMI Analysis

At the workshop, additional questions surfaced about which customer classes are to be included in the AMI system cost benefit analysis. Some parties indicated they plan to propose deployment of an AMI system serving only the mass market (residential and small commercial customers).

We clarify that the Commission anticipates that full scale implementation of AMI will provide **all** customers in **all** rate classes with the option to choose between dynamic and static rate structures. We are not interested in an analysis of the costs and benefits of AMI that is limited to residential or small commercial customers because system benefits inure to all customer classes that cannot be separated from the costs of AMI deployment. While we can compartmentalize the costs of AMI and load control systems to specific customer classes, it is not possible to isolate the benefits from demand response to one or more customer class since the system-wide benefits of demand response will flow to all classes. Thus the costs and benefits to of deploying an AMI system all customer classes must be quantified.

5. Costs to be Included in Base Case AMI Scenario

The September 19, 2003 ruling indicated that "(t)he Base Case must identify the actual costs of maintaining the existing metering and related support systems" and "identify the any significant investments in new metering systems made during the last five years." (See September 19, 2003 Assigned Commissioner and Administrative Law Judge's Ruling, Attachment A, p. 7.) Despite this guidance, at the January 28, 2004 workshop, some parties proposed to develop incremental cost estimates for the full and partial deployment of AMI scenarios without describing their estimates of maintaining their metering and billing systems in the base case. This information is important because without knowing what additional costs utilities have recently incurred and are expect to incur in the next several years for existing metering, billing, and other back office systems, it is impossible to develop an accurate estimate of the incremental costs of partial or full scale AMI deployment. Thus we expect the scenario analysis to include a full accounting of all of the costs of installing and maintaining the metering and related support systems for the base case, partial deployment and full scale AMI deployment scenarios.[4]

6. Methodology to use in the Valuation of Demand Response Benefits

At the workshop some participants suggested there was a need to hold a workshop to develop a common methodology to quantify avoided costs for use in valuing peak demand reductions. We agree that a workshop on this topic would be useful and direct the WG3 moderator to schedule a workshop to review potential sources of avoided costs for inputs in the AMI business case analysis.[5]

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[4] For example, the analysis should identify whether separate metering, billing, customer information, and communication systems will serve each customer class or a common system will serve all customers, whether new systems will be developed or existing systems can be modified to achieve the same functionality and the potential cost of these options.

[5] We note that on February 6, 2004, the Assigned Commissioner in R.01-08-028 (the Energy Efficiency Rulemaking) issued a ruling setting a workshop in June 2004 to address issues surrounding avoided costs. (See http://www.cpuc.ca.gov/WORD_PDF/RULINGS/33895.doc.) We do not intend to duplicate the purpose of that workshop here but hope that the workshop in this docket will allow us to provide guidance on what avoided cost inputs should be utilized in the AMI business case analysis on a more expedited schedule than would be possible were we to await the results of the workshop in R.01-08-028.

Participants also suggested that a workshop be held to develop a common methodology to estimate the level of demand response that could be available by customer class as a result of the AMI deployment scenarios. We are not sure if having a workshop on the demand response impact methodology is appropriate now given that WG3 is focused on reviewing load impacts from the Statewide Pricing Pilot and WG2 members are focused on developing estimates of demand response impacts for the March 31, 2004 filing. We solicit input from parties on the need to hold a workshop on methodologies for estimating demand response in the near term. Parties should provide their input to the WG3 moderator via email (Mmesseng@energy.state.ca.us) with a copy to ALJ Cooke (mlc@cpuc.ca.gov) by February 25, 2004.

7. "Out of Scope" Impacts

Some parties appear to have misunderstood the "out of scope" categorization of impacts referenced in the November 24, 2003 Assigned Commissioner's Ruling. "Out of scope" is intended to mean the impact will not be relevant to the decision of this proceeding. "Out of scope" does not mean "difficult to quantify" or "unrelated to utility cash flow" as some parties appear to suggest. We expect that impacts will be assessed at some level, whether using rigorous quantitative methods or more qualitatively. To the extent that assessments have to rely upon limited data (creating greater uncertainty about a particular cost or benefit), it is appropriate to document these instances in the actual AMI analysis.

Therefore, **IT IS RULED** that:

1. The advanced metering infrastructure (AMI) system analyzed should (at a minimum) support the functions set forth in Section 3 herein.

2. The costs and benefits of deploying an AMI system to all customer classes must be analyzed in the business case.

3. Expected costs for maintaining existing metering, billing, and other back office systems must be quantified as part of the base case scenario.

4. The Working Group 3 (WG3) moderator should schedule a workshop to review potential sources of avoided costs for inputs into the business case analysis.

5. Parties should provide input to the WG3 facilitator by email (Mmesseng@energy.state.ca.us) with a copy to ALJ Cooke (mlc@cpuc.ca.gov) by February 25, 2004 about the need to hold a workshop in the near term on methodologies for estimating demand response.

6. Difficult to quantify impacts should still be assessed in the AMI analysis, even if a more qualitative assessment is required to do so.

Dated February 19, 2004, at San Francisco, California.

/s/ MICHAEL R. PEEVEY	/s/ MICHELLE COOKE by LTC
Michael R. Peevey Assigned Commissioner	Michelle Cooke Administrative Law Judge

Appendix A

Previous Guidance on the Scope of the AMI Analysis

From Decision 03-06-032, Attachment A, p. 3.

- Technologies to enable demand response may also provide other customer service benefits including outage detection and management, power quality management, and other information capabilities

  …
- Customers should have the ability to choose voluntarily among various tariff options, including:
  - Very large customers (over 1 MW): Hourly real-time pricing (RTP), critical peak pricing (CPP), or Time-of-Use (TOU) Pricing
  - Large customers (200 kW to 1 MW): CPP, TOU or RTP
  - Residential and small commercial customers (under 200 kW): CPP, TOU or flat rate (the latter with an appropriate hedge for risk protection)"

  …
- All customers should be provided an advanced metering system capable of supporting a TOU tariff or better, if cost-effective, and with minimal hardware upgrades necessary to choose among various dynamic tariffs.
- All customers who choose to should be able to conveniently access their usage information using communications media (e.g., over the internet, via on-site devices, or other means chosen by the customer and respectful of potential privacy concerns)
- The broadest possible range of metering and communications technologies that can enable demand response should be encouraged (i.e., optionality), but all technologies should be compatible with utility billing and other back-office systems

Additional guidance on the definition of full scale AMI implementation was presented in the draft analysis framework attached to the September 19, 2003 ruling. Full implementation was described as follows:

> Assumes full system implementation (gas and electric) over a five-year period with support for TOU, Critical Peak Pricing and two-part RTP for the largest C/I customers. Implementation should specify an advanced metering infrastructure (AMI) with interval metering (minimum 15 minute intervals) and remote communication capability. Useful modifications to outage detection

and other operating systems that are associated with the use of the AMI system should also be specified.

BILL NUMBER: SB 441 AMENDED
BILL TEXT

AMENDED IN ASSEMBLY AUGUST 22, 2005
AMENDED IN ASSEMBLY JULY 12, 2005
AMENDED IN SENATE MAY 3, 2005
AMENDED IN SENATE APRIL 4, 2005

INTRODUCED BY Senator Soto

FEBRUARY 17, 2005

An act to add Section 739.11 to the Public Utilities Code, relating to electricity.

LEGISLATIVE COUNSEL'S DIGEST

SB 441, as amended, Soto Electricity: rates: advanced metering infrastructure.
~~Under~~
(1) *Under* existing law, the Public Utilities Commission has regulatory authority over public utilities, including electrical corporations. Existing law authorizes the commission to fix the rates and charges for every public utility, and requires that those rates and charges be just and reasonable. Existing law requires electrical corporations furnishing electricity to an agricultural producer to prepare and file tariffs providing for optional off-peak demand service, including the availability of time-differentiating meters or other measurement devices.
This bill would, with certain exceptions, prohibit the commission from requiring the installation of advanced metering infrastructure, as defined, for any building constructed prior to January 1, 2006, and occupied by a customer with average annual electricity usage of less than 1,000 kilowatthours per month, unless the commission first evaluates certain factors, as specified.
~~Under~~
(2) *Under* existing law, a violation of the Public Utilities Act or an order or direction of the commission is a crime.
Because the provisions of this bill would be a part of the act and a violation of any of those provisions would be a crime, the bill would impose a state-mandated local program by creating a new crime.

~~The~~
(3) *The* California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.
This bill would provide that no reimbursement is required by this act for a specified reason.
Vote: majority. Appropriation: no. Fiscal committee: yes. State-mandated local program: yes.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. The Legislature finds and declares all of the following:

(a) The Public Utilities Commission is currently considering authorizing or requiring electrical corporations to install advanced metering infrastructure (AMI) for their customers, including all existing residential and small commercial customers, regardless of their size or location.

(b) Electrical corporations have already requested over one hundred twenty million dollars ($120,000,000) to spend in 2005 in order to prepare to install AMI in early 2006.

(c) The entire statewide cost of AMI installation is estimated at several billion dollars.

(d) The commission has not conducted any evidentiary hearings to determine whether universal installation of AMI for small customers will be cost effective for those customers.

SEC. 2. Section 739.11 is added to the Public Utilities Code, to read:

739.11. (a) For purposes of this section, "advanced metering infrastructure" means interval data recording meters, along with two-way communications and any other equipment necessary for the installation and operation of the meters.

(b) Except as provided in Sections 353.3 and 393, the commission shall not require the installation of advanced metering infrastructure for any building constructed prior to January 1, 2006, and occupied by a customer with annual average usage of less than 1,000 kilowatthours per month, unless it first evaluates the following:

(1) The effect on average annual electricity rates for residential and small commercial customer classes for every year of repayment for the AMI investment.

(2) The bill impacts of any proposed mandatory time-differentiated rates on residential customers in hot climate zones.

(3) The amount of peak load reduction contrasted with other demand reduction program alternatives.

(4) The *feasibility and* cost effectiveness of partial deployment in selected zones contrasted with deployment throughout an entire service territory of an electrical corporation.

SEC. 3. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

Sacramento Business Journal

State OKs PG&E 'smart meters'

Sacramento Business Journal - July 25, 2006

The California Public Utilities Commission has approved Pacific Gas & Electric Co.'s plan to install advanced meters for virtually all the utility's electric and gas customers, the company said in a regulatory filing Tuesday. The new meters would allow the utility to read meters from a distance and charge prices that vary depending on the demand for power.

The automated devices, known as SmartMeters, would be installed starting in the fourth quarter, with installation completed in 2011. The new meters, approved Monday by the commission, are designed to improve customer service by enabling the utility to read them using a remote network. One benefit of the new meters will be the utility's ability to more quickly respond in a power outage, the company said in a Securities and Exchange Commission filing Tuesday. PG&E is owned by San Francisco-based **PG&E Corp.** (NYSE: PCG).

A plan for PG&E to recover the estimated project cost of $1.74 billion from ratepayers also was approved by the PUC. The hefty price tag includes $1.68 billion for project costs and approximately $54.8 million related to marketing a new pricing plan. The PUC approved rate recovery for PG&E of 90 percent of up to $100 million if the project's total costs exceed the $1.68 billion. Those additional costs can be recovered without a reasonableness review, the company said.

The PUC also approved PG&E's proposal to offer customers the new billing option that it calls critical peak pricing. This option will allow customers to take advantage of electricity prices that vary by day and hour, potentially reducing their bills and shifting energy use away from critical peak period.

PG&E expects that as much as 89 percent of the new meter project costs will be offset by anticipated operational savings and efficiencies. Demand may also be reduced by customers who choose the critical peak billing option, the company said.

Application No.: A.05-03-
Exhibit No.: SCE-1
Witnesses: J. Fielder
D. Kim
L. Ziegler

(U 338-E)

Testimony Supporting Application for
Approval of Advanced Metering
Infrastructure Deployment Strategy
and Cost Recovery Mechanism

Volume 1 – Business Vision, Management
Philosophy, and Summary of Business Case Analysis

Before the Public Utilities Commission of the State of California

Rosemead, California
March 30, 2005

EXECUTIVE SUMMARY

Southern California Edison Company (SCE) has completed an extremely rigorous business case analysis of Advanced Metering Infrastructure (AMI). SCE's findings indicate that an integrated AMI solution that leverages additional commercially-available technologies has the potential to provide an effective platform for enhancing routine customer services, providing more sophisticated alternatives for load management and demand response, and increasing operational efficiencies and benefits. However, these enabling technologies have yet to be cost-effectively packaged or integrated into a streamlined meter for application in the United States. Therefore, SCE has concluded that given its operational starting point, an investment in currently-available AMI technology is not cost effective for SCE's customers. Instead, SCE proposes to achieve significant increased operational and demand response benefits through a concerted and aggressive effort to develop an "advanced integrated meter" (AIM) that integrates additional technologies into the next generation of meters.

SCE's business vision for AMI seeks to undertake a deliberate, yet fast-paced effort to design and develop a new AIM platform that will better meet SCE's and its customers' needs by integrating additional proven technologies. The goal of the AIM project will be to add significantly more functionality at the same or lower cost as today's solutions, in order to significantly increase benefits over the current AMI business case.

The AIM development will take a "clean sheet" approach to design a meter that provides additional functional capabilities not available in currently-available metering solutions, including the possible integration of load control, demand limiting, two-way communications, customer information displays, data storage, and/or other proven stand-alone technologies. SCE seeks to significantly increase overall durability and versatility of AMI by using open, extensible and

multifunctional meter and communications platforms. The AIM project is expected to leverage commercially-available components through an open design for both the meter device and communications to provide a flexible and sustainable technology platform during its long lifecycle. This is essential given recent and anticipated future technology developments in home connectivity, distribution grid intelligence, distributed generation, and broadband over power lines, all of which may interface with the AIM technology.

SCE has developed a detailed strategy and aggressive timeline for the AIM development project that allows for integrated meter design, prototype development, beta production, and pilot test before a new business case would be prepared for Commission approval of full deployment. If there are no major obstacles and the AIM technology delivers its promised improvements to the business case analysis, SCE envisions completing full deployment of the new AIM system no later than one to two years after the time that full deployment of today's AMI technology could be completed. SCE's customers would nevertheless be advantaged, despite this slight delay, given the superior attributes of the proposed AIM technology, including more durability, versatility and the ability to deliver significant improvements in system reliability, customer billing and service options, outage management and operational efficiencies. Thus, it is critical that SCE's ultimate investment in AMI focus on "getting it right" instead of rushing to "get it done."

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.
Application 05-03-015.

EXCERPTS FROM
CHAPTER 2
PREPARED DIRECT TESTIMONY OF EDWARD FONG

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA.

March 15, 2005

I. INTRODUCTION

The purpose of this testimony is to provide a summary of: 1) San Diego Gas & Electric Company's (SDG&E) management philosophy and business vision regarding Advanced Metering Infrastructure (AMI), dynamic pricing[1] and demand response, and the overarching policy issues that the Commission must consider with the implementation of AMI and dynamic rates; 2) SDG&E's recommended preferred optimum deployment scenario; and 3) other regulatory and financial factors impacting SDG&E's AMI business case.

SDG&E continues to be a strong proponent of, and leader in, integrating AMI, dynamic rates and demand response. SDG&E's AMI business case preliminary analysis,[2] supplemental analysis,[3] and this application demonstrate (over the analysis horizon through 2021), that, under a preferred default dynamic pricing scenario, AMI and dynamic rates provide sufficient estimated operational and demand response benefits to justify a full or partial scale AMI deployment.

A. Costs Benefits Analysis

SDG&E's updated AMI cost and benefit analysis is contained in Chapter 6 of this application. As specifically indicated, operational benefits from AMI alone do not justify full or partial deployment of AMI. The combination of demand response benefits (i.e. capacity and energy) and operational benefits are required to justify AMI deployment…. (pp. EF2-1 – EF2-2.)

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[1] Dynamic pricing, dynamic rates, demand response rates, time differential rates and other similar phases are used interchangeably throughout all aspects of this application.
[2] SDG&E's October 22, 2004 filing on the "Preliminary Analysis Regarding Advanced Metering Infrastructure Business Case".
[3] SDG&E's January 12, 2005 supplemental filing updating the October 22, 2004 filing, "Advanced Metering Infrastructure (AMI) Business Case Supplemental Filing".

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II. SDG&E's MANAGEMENT PHILOSOPHY AND AMI BUSINESS VISION

As stated in SDG&E's October 22, 2004 "Preliminary Analysis Regarding Advanced Metering Infrastructure Business Case," SDG&E has long been a strong advocate for implementation of advanced metering technologies and movement of customers to demand response rates. Not only will demand response benefits emerge from the implementation of AMI and dynamic rates, but customers will have energy usage information to make informed decisions regarding their individual demand and load profiles. Specifically, customers will have the ability to determine their incremental or marginal energy usage depending on a time differentiated energy price signal. Because retail electric prices will be time differentiated, many customers will likely choose more efficient appliances, automated energy management systems, and load control devices.

Under current flat or tiered rate structures, residential customers are essentially insulated from wholesale electric market prices that vary with market and system conditions. This disconnect from the wholesale market distorts the demand and supply conditions by further exacerbating higher demand during peak hours, thereby leading to a possible gap between demand and supply. In response, SDG&E was the first utility in California to request that the Commission authorize the implementation of "Real-time Energy Meters" and dynamic rates in 2000 in application A.00-07-055…. (p. EF2-7.)

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III. OVERARCHING POLICY CONSIDERATIONS

A. Voluntary Demand Response Programs Alone are Insufficient

A necessary condition for AMI to achieve sufficient and significant demand response benefits is the simultaneous deployment of dynamic rates. Without dynamic rates, customers would have little or no incentive to reduce demand during critical peak periods. Voluntary demand response programs alone are insufficient to achieve the 5% demand response targets established in this proceeding and restated in the Energy Action Plan. Voluntary programs will always have some element of "free ridership." In particular, customers with flatter than the class average or system load profiles will benefit from enrolling in a voluntary dynamic rate program, while providing little, or no, demand reductions during the peak periods to achieve such benefits…. (p. EF2-9.)

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C. Various Dynamic Rate Options and Demand Response Programs Must Be Available

SDG&E believes that the Commission must determine the appropriate dynamic rate structure to induce demand response that reflects the levels presented in this application. Various dynamic rate options should be made available to customers. The analysis of potential demand response impacts was completed for this filing using illustrative dynamic rate structures specified by the Commission. A comprehensive set of dynamic rate structures must be in place, since the primary objective of AMI deployment is to enable time-differentiated rates, and indeed, the key cost justification of AMI is the demand response impact that result from such price signals. The Commission must commence a proceeding to address dynamic pricing and establish various rate options that can be made available to customers in order to achieve the equivalent demand response impacts set forth in this Application. SDG&E is not advocating one dynamic rate structure over others in this application. Nevertheless, dynamic rates are necessary to induce demand response benefits that are stated in above Table EF2-1…. (p. EF2-11.)

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IV. SDG&E'S OPTIMUM DEPLOYMENT PLAN

A. Plan for Full Deployment

SDG&E's optimum AMI plan assumes a full-deployment scenario with a carefully targeted phased implementation. SDG&E proposes that, if key assumptions driving the estimated costs and benefits contained in SDG&E's business case analysis do not materialize, AMI deployment off-ramps be utilized to protect AMI investments….
(p. EF2-14.)

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B. Target Inland Climate Zone & C&I First
C. Reevaluation Off-ramps or Gate Decision for Continuing Full Deployment

SDG&E proposes that the initial deployment be completed for the Inland Climate Zone and all C&I customers over 20 kW. If, during the initial deployment phase in the Inland climate zone, economic or dynamic rate assumptions appear to materially impact SDG&E's business case assumptions, then SDG&E proposes that deployment to the Coastal climate zone residential and small commercial customers be delayed until conditions change to warrant the expanded deployment. It must be noted that SDG&E costs incurred to date should remain recoverable.

Specifically, SDG&E proposes that the following condition be monitored during the Inland climate zone deployment phase:

1) **Dynamic rates are not adopted by the Commission for all customers that will achieve the equivalent demand response impacts set forth in this Application.** Full deployment to Coastal climate zone residential and small commercial customers (remaining 60%) of SDG&E's customer base) should be deferred until such rates are in place.
2) **Customer opt-out rates from default dynamic rates after the first year (2007) of deployment appear to exceed 40%.** The business case assumes an approximate 20% opt-out rate. A 40% or greater opt-rate will trigger the off-ramp. Deployment to

Coastal residential and small commercial climate zone customers will be deferred until changes in the rate design are implemented to reduce the opt-out rate.

3) **Deployment or installation price points for residential customers (meters, communications hardware, installation labor costs) exceed estimated price points contained in the business case by 20%.** Deployment would be suspended for the Coastal climate residential and small commercial customers until price points are sufficiently low to justify the continuation of full deployment.
4) **Software development cost for AMI meter data management systems appear to be exceeding business case estimates by 50%.** Deployment will be deferred for Coastal climate zone residential and small commercial customers until expanded deployment is justified.
5) **Recovery of existing meters.** SDG&E intends to recover the remaining book value of the installed costs for the existing meters consistent with current ratemaking treatment adopted by the Commission, using the normal straight-line remaining-life depreciation practice. SDG&E will recover the installed cost of the existing meters over the average remaining life prior to implementation of AMI technology. If SDG&E does not receive recovery of the existing meters over their remaining life, then SDG&E reserves the option to suspend AMI development…. (p. EF2-14 – EF2-16.)

GRID AUTOMATION

Jesse Berst

Feb 12, 2006

The Dangers of Advanced Metering

AUTHOR BIO EMAIL INFO EASY PRINT

The Center for Smart Energy just completed custom research into the advanced metering sector. Although I can't share the proprietary results and recommendations, I can pass along a few observations.

This is a dangerous time to be a metering buyer or vendor.

Don't get me wrong – I consider advanced metering essential to the Smart Grid. Today's products can provide remarkable benefits and a quick payback... if you get a system designed with the future in mind.

And there's the rub. The sector is in such turmoil – and so many people are blind to what's around the corner – that a utility can easily end up with a dead end system. With technology that cannot expand to give you the full benefits. Or a pricing model that gouges you for years. Or a proprietary system that puts you at the mercy of a single vendor. Or a vendor that doesn't survive the coming consolidation, and strands you without adequate support and upgrades.

Everything in this sector is changing – regulations, pricing, business models and, of course, technology. It's exciting, but confusing and risky as well. Out of the several dozen findings from our research, let me highlight the top seven and then suggest a few ways to mitigate the risks.

The vendor landscape is chaotic and misleading. Almost all top-tier vendors underwent an ownership change in the last five years. Meanwhile, several dozen upstarts have muscled their way into contention. Picking the right supplier is fraught.

Metering hardware is undergoing several transitions. The changeover from electromechanical to digital is well established and well understood. Two other transitions are now underway, even though many market participants seem unaware of the implications: a) from separate to integrated and b) from custom-built to commodity.

Metering hardware prices are headed down. In line with my "commoditization" prediction above, I believe North American prices for advanced meters will drop 50% by 2009.

One-way mobile AMR is a dead end. It may be cheaper to install, but it locks you away from the many benefits of true, two-way advanced metering.

Meter data management (MDM) is key to getting full value so you can expect any vendor with half a brain to add MDM software and solutions to its product line.

Open standards in general (and the Zigbee wireless standard in particular) will disrupt business as usual. Utility buyers are coming to understand that standards bring lower prices and greater choice. Vendors who drag their feet will lose market share.

It is still too early to predict a winner on the communications side. Although I have my favorites (Zigbee for residential, for instance), it is still too early to know which communications network will become the preferred option. Choices range from cellular to BPL to GPRS to satellite and a dozen more, each with its pros and cons.

Navigating the Mine Field

Despite the confusion, I do not advocate waiting. Advanced metering is too important and too empowering. But I do suggest looking for a system that can accommodate the future. In particular, be on the watch for:

- **Low total cost of ownership.** A low first cost can mask higher lifetime costs. Some systems charge for every read, making it expensive to poll meters as often as you might want. Some make it expensive to add new capabilities. Some have hidden maintenance and upgrade needs.
- **No ceiling on expansion**. Most buyers wisely start with a just few core applications. Eventually though, you'll want to expand. To new customer classes. To new neighborhoods. To other kinds of meters if you also handle water or gas. To new applications such as outage management, load profiling, remote connect/disconnect, and many more. Some choices lock you away from easy expansion or make it too expensive.
- **Communications flexibility**. Do not try to guess which communications technology will be the ultimate winner. Instead, buy a system that can communicate through any major network, without the need to rip out the meters and start over.
- **A single place to point your finger** (aka one @$$ to kick)**.** It may be tempting to buy the pieces and assemble them in house. But given the complexity and state of flux, I suggest instead that you look for a vendor that can (by itself or with partners) create a turnkey project team. Make sure meter data management is part of the package.

There is no shortage of articles touting the benefits of advanced metering. Few, if any, point out that this sector will change more in the next three years than in the past twenty. In this atmosphere of flux and volatility, you must consider more than today's needs. You must also keep the door open for tomorrow's revolution.

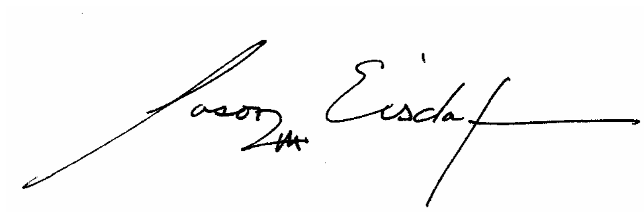
In that spirit, I have listed three sites that can help you assemble your own tools for monitoring and profiting from this important sector.

MADRI Advanced Metering Infrastructure Toolbox
Southern California Edison Advanced Metering Infrastructure program
AMI / MDM Working Group
Email Jesse with comments

CERTIFICATE OF SERVICE

I hereby certify that on this 9th day of August, 2006, I served the foregoing General Rate Case Direct Testimony of the Citizens' Utility Board of Oregon in docket UE 180 upon each party listed below, by email and U.S. mail, postage prepaid, and upon the Commission by email and by sending 6 copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

Respectfully submitted,



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