BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY

Respondent.

DOCKETS UE-190529 and UG-190530 (*Consolidated*)

RESPONSE TESTIMONY OF PAUL J. ALVAREZ
ON BEHALF OF THE
WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL
PUBLIC COUNSEL UNIT

EXHIBIT PJA-1T

November 22, 2019

DOCKETS UE-190529 and UG-190530 (*Consolidated*)

RESPONSE TESTIMONY OF PAUL J. ALVAREZ

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I. INTRODUCTION AND PREVIEW

Q. Please state your name and business address.

A. My name is Paul J. Alvarez. My business address is PO Box 620756, Littleton, CO 80162.

Q. By whom are you employed and in what capacity?

A. I am the President of the Wired Group, a consulting practice specializing in the distribution utility planning, investment, and performance. In this capacity, I consult for consumer, business, and environmental advocates and state utility commissions on issues related to the quality and cost-effectiveness of distribution utility grids and businesses. I also manage the affairs of the business, including associate and subcontractor recruiting and management, business development, and administration.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Public Counsel Unit of the Washington State Attorney General's Office.

Q. Please describe your professional qualifications.

A. My career began in 1984 in a series of finance and marketing roles of progressive responsibility for large corporations, including Motorola's Communications Division (now Android/Google), Baxter Healthcare, Searle Pharmaceuticals (now owned by Pfizer), and Option Care (now owned by Walgreens). My combined aptitude for finance and marketing were well suited for innovation and product development, leading to my first job in the utility industry in 2001 with Xcel Energy, one of the largest investor-owned utilities in the U.S.

At Xcel Energy, I served as product development manager, overseeing the development of new energy efficiency and demand response programs for residential, commercial, and industrial customers, as well as programs in support of voluntary renewable energy purchases and renewable portfolio standard compliance (including distributed solar incentive program design and metering policies). There, I learned the economics of traditional monopoly ratemaking and associated utility incentives, as well as the impact of customer self-generation, energy efficiency, and demand response on utility profits and management decisions. I also learned a great deal about utility program benefit quantification (measurement and verification, or "M&V").

I left Xcel Energy to lead the utility practice for sustainability consulting firm MetaVu in 2008. At MetaVu, I employed my M&V experience to lead two comprehensive, unbiased evaluations of smart grid deployment performance. To my knowledge these are two of only three comprehensive, unbiased evaluations of smart grid post-deployment performance completed to date. The results of both were part of regulatory proceedings in the public domain and include an evaluation of the SmartGridCity™ deployment in Boulder, Colorado for Xcel Energy in 2010,[1] and an

[1] Paul J. Alvarez, et al, MetaVu. SMARTGRIDCITY™ DEMONSTRATION PROJECT EVALUATION SUMMARY" (Oct. 21, 2011), available at http://nebula.wsimg.com/964db667494457ab2d7e28f15232b7a2?AccessKeyId=8AF7098D30C5BF55909C&disposition=0&alloworigin=1. Report submitted to the Colorado Public Utilities Commission in the testimony of Michael G. Lamb, Exhibit MGL-1, proceeding 11A-1001E, filed December 14, 2011.

evaluation of Duke Energy's Cincinnati-area deployment for the Ohio Public Utilities Commission in 2011.[2]

In 2012, I started the Wired Group to focus exclusively on distribution utility businesses and operations as they relate to grid modernization, demand response, energy efficiency, and renewable generation. In addition, I serve as an adjunct professor at the University of Colorado's Global Energy Management Program, where I teach an elective graduate course on electric technologies, markets, and policy. I have also taught at Michigan State University's Institute for Public Utilities, where I have educated new regulators and PUC staff on grid modernization and distribution utility performance measurement.

Finally, I am the author of <u>Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment</u>, a book that helps laypersons understand smart grid capabilities, optimum designs, and post-deployment performance optimization. I am also the developer of the Utility Evaluator, an Internet-based software program which benchmarks distribution utility performance against peers with like characteristics using publicly available financial and operating performance data.

I received an undergraduate degree from Indiana University's Kelley School of Business in 1983, and a master's degree in Management from the Kellogg School at

[2] Alvarez et al, MetaVu. DUKE ENERGY OHIO SMART GRID AUDIT AND ASSESSMENT (June 30, 2011), available at http://nebula.wsimg.com/5cbd3a404d5a8245caef27c6af9b9cf2?AccessKeyId=8AF7098D30C5BF55909C&disposition=0&alloworigin=1. Report to the Staff of the Public Utilities Commission of Ohio in proceeding 10-2326-GE-RDR.

Northwestern University in 1991. Both degrees featured concentrations in Finance and Marketing.

Q. Have you previously appeared before the Washington Utilities and Transportation Commission?

A. No, I have not. However, I have testified in, or served as a consultant to clients in 18 states in support of cases before state utility regulatory commissions. I have consulted on cases regarding smart meters, rate design, grid modernization, distribution planning processes, and distribution utility performance. Please see Exhibit PJA-2 for a complete list of my regulatory appearances.

Q. What is the purpose of your testimony in this proceeding?

A. I address Puget Sound Energy's (PSE) deployment of advanced metering infrastructure (AMI or "smart meters").

Q. Please summarize your testimony.

A. I recommend the Commission reject PSE's request for recovery of and on capital spent to implement its AMI system. Public Counsel witness Mark Garrett explains that the disallowance removes test year plant of $13.8 million, which result in a revenue requirement reduction of $4.2 million.[3] My recommendation is based on the following arguments:

[3] Response Testimony of Mark E. Garrett, Exh. MEG-1T at 19:6-16. The test year disallowance is in addition to Mr. Garrett's adjustment to remove PSE's post-test year adjustment and attrition adjustment.

- The incremental cost of PSE's AMI deployment will exceed the benefits to customers by a wide margin because PSE's AMI business case dramatically understates costs and dramatically overstates benefits;
- A less costly option was available to secure the outcomes PSE claimed from AMI, including conservation voltage reduction and the resolution of problems with the existing metering system.

Finally, I recommend the Commission open a proceeding to develop a more open, stakeholder-engaged distribution business planning and capital budgeting process to help avoid such issues in the future.

II. PSE'S AMI BUSINESS CASE DRAMATICALLY UNDERSTATES COSTS

Q. Please briefly describe PSE's AMI business case.

A. The AMI business case explains why PSE chose to deploy AMI, estimates both the costs and the benefits of the AMI deployment, and describes the AMI implementation plan.

Q. Please describe the total costs and benefits in the PSE's AMI business case.

A. PSE's AMI business case claims that the costs of the AMI deployment will be $473 million,[4] and claims that the benefits of the AMI deployment will be $668 million.[5] Though PSE does not say so directly, the result is a claimed net benefit to customers (benefits less costs) of $195 million.

Q. Do you agree with PSE's AMI business case?

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[4] Catherine A. Koch, Exh. CAK-4, Appendix A (AMI Business Case) at 6.
[5] *Id*. at 7.

A. No.

Q. Please explain why you oppose the Company's AMI business case.

A. The AMI business case does not include all of the costs customers will pay for PSE's decision to implement AMI. Furthermore, the AMI business case overestimates the benefits customers will receive. I will discuss the understated costs in this section of my testimony, and the overstated benefits in the next section of my testimony.

Q. Please describe how PSE's AMI business case dramatically understates meter costs.

A. PSE's business case dramatically understates the cost of its AMI deployment in two ways. First, PSE did not include almost $127 million in legacy meter equipment book value PSE abandoned to make way for AMI in its cost estimate. The failure to consider the cost of the installed metering equipment removed from service prematurely unfairly biased PSE's decision to implement AMI.

Second, PSE did not include carrying charges customers will pay on abandoned legacy meter equipment until it is fully depreciated. As I describe in detail below, I estimate these carrying charges to be $62.5 million. I summarize these costs omitted from PSE's business case, totaling $189.4 million, below.

Table 1
Understated AMI Project Costs

AMI Project Costs to Customers per PSE[6]	$472.7m
Plus: Book value of metering components replaced prematurely	126.8m
Plus: Carrying charges on metering components replaced prematurely	62.5m
Total cost adjustments:	$189.3m
Actual AMI Project Costs to Customers per Public Counsel:	$662.0m

Q. How significant are PSE's legacy metering system costs?

A. In discovery, PSE reported that the book value of legacy equipment replaced as of June 30, 2019, was $102.8 million for electric meters, $23.8 million for gas meter data transmitters, and $0.2 million for AMR nodes,[7] for a total of $126.8 million. This amounts to about $90.66 per electric customer and $28.45 per gas customer, not including the carrying charges customers have yet to pay on these capital balances. Carrying charges borne by customers include PSE's authorized return on equity, federal income taxes on profits, state sales taxes on revenues, and interest expense.

Q. Does PSE give an explanation as to why the legacy meter costs are not included in the AMI business case?

A. No.

Q. Why should the legacy meter costs be considered in PSE's AMI business case?

A. PSE's decision to replace its existing meters was discretionary, not mandatory. PSE decided to implement the AMI system, including new electric meters, new gas meter data

[6] Koch, Exh. CAK-4, Confidential Appendix G, tab "Scope Summary", cell D72.
[7] Paul J. Alvarez, Exh. PJA-4, PSE 1st Revised Response to Public Counsel Data Request No. 70.

transmitters, and a new meter communications network. In doing so, it simultaneously made the decision to remove its existing electric meters, gas meter data transmitters, and meter communications network.

PSE attempts to justify replacing its current metering system with the equipment's impending failure rates. In particular, PSE witness Ms. Koch states that the gas meter data transmitter batteries were due to start failing.[8] The AMR nodes (for electric and gas meter communications) were failing at a rate of four percent annually,[9] and the electric meters were failing at a rate of only 1.6 percent annually.[10]

PSE's equipment failure rate is not significant and did not pose a situation requiring immediate action. Transmitter batteries can be replaced, albeit at a cost. Regardless, PSE could have considered replacing transmitter batteries over replacing its entire metering system. Moreover, I consider PSE's existing meter equipment to be performing well for equipment designed to last 20 to 30 years (i.e., with an expected failure rate of 1.6 percent to 2.5 percent annually), and the AMR nodes to be performing at a level to be expected for equipment designed to last 10 years on average (i.e., with an expected failure rate of five percent annually).

The cost to customers of the equipment being removed from service prematurely, rendering that equipment no longer used and useful, is highly relevant to PSE's discretionary decision. Because PSE's decision to implement AMI is discretionary, PSE

[8] Koch, Exh. CAK-4 at 4:17.
[9] *Id*. at 4:15.
[10] *Id*. at 4:16.

should have considered the cost of prematurely removing the existing equipment in its cost-benefit analysis.

Notably, other regulators, including Massachusetts' Department of Public Utilities, are very concerned about the costs of legacy equipment being removed from service prematurely to make way for AMI systems. In fact, the high cost of legacy systems was one reason the Massachusetts Department delayed AMI deployments in that state.[11] The associated costs for PSE's electric customers are more significant on a per-customer basis than they were in Massachusetts. In Massachusetts, legacy metering systems had an average book value, not including carrying charges, of $76 per customer.[12]

Q. What are carrying charges?

A. Carrying charges are costs customers must pay to cover a utility's investment financing costs, including its return on equity, interest expense on debt, federal income taxes on utility profits, and sales taxes on revenues.

Q. Why should PSE have included the carrying charges associated with the legacy equipment in its AMI benefit-cost analysis?

A. A benefit-cost analysis is used to determine whether the benefits of an investment to customers exceed the cost to customers. Carrying charges are something customers must

[11] *Petition of Mass. Elec. Co. and Nantucket Elec. Co. for Approval of its Grid Modernization Plan*, D.P.U. 15-120, 15-121, and 15-122/123, Order at 121-122 (May 10, 2018) available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9163509.
[12] *Id*. Exiting meter book value of $210 million divided by 2.76 million electric customers (Eversource, Massachusetts Electric/National Grid, Western Massachusetts Electric/Eversource, and Fitchburg Gas & Electric) is $76 per customer.

pay. Thus, to ensure an “apples-to-apples” comparison of customer benefits to customer costs, carrying charges must be included in customer costs.

Q. Will customers pay for equipment, as well as carrying charges on equipment, that has been removed from service and is no longer used and useful?

A. Absent specific Commission action, yes. In discovery, PSE reported that nine years of depreciation remained on its old electric meters, and 14 years of depreciation remained on its old gas meter data transmitters and AMR nodes.[13] Using these remaining years of life, the remaining book value, and PSE’s own revenue requirements calculations in this case as a template,[14] I conservatively estimate that the carrying charges customers will pay on the existing assets removed from service prematurely will be an additional $62.5 million.[15] The details behind my estimate are provided in Exhibit PJA-5.

Q. Please describe how you estimated the carrying charges.

A. I estimated carrying charges by calculating total revenue requirements over the remaining useful lives of the assets removed, and then subtracting the return of capital (depreciation expense) to determine the amount customers will pay over and above the return of capital. I estimated revenue requirements in the traditional manner: 1) by adding the requested rate of return (9.8 percent) on the equity portion of the rate base (48.5 percent); 2) by adding federal income taxes on that return (21 percent); 3) by adding the interest expense (5.57 percent weighted average cost of debt) on the debt portion of the rate base

[13] Alvarez, Exh. PJA-5, PSE Response to Public Counsel Data Request No. 146, Attachment A, lines 68 (electric), 76 (gas), & 91 (AMR nodes).
[14] Susan E. Free, Exh. SEF-3.
[15] Alvarez, Exh. PJA-3, Calculation of Carrying Charges on Legacy Equipment.

(51.5 percent); and 4) by grossing up the resulting amount by the state sales tax (4.52 percent). After completing this process for the first year, I repeated it for every subsequent year of the remaining asset lives (nine years for the electric meters removed and 14 years for both the gas meter data transmitters and AMR nodes),[16] reducing the size of the rate base each year by the amount of the previous year's depreciation until the equipment was fully depreciated ($0 book value remaining).

Q. Please summarize your recommendation regarding PSE's understated metering costs.

A. PSE's AMI cost estimate should be increased to include the value of equipment removed from service prematurely and the carrying charges on this value. The value of the equipment removed from service prematurely is $126.8 million, and I estimate the carrying charges to be an additional $62.5 million, for a total increase of $189.3 million. This is a 40 percent increase over PSE's AMI cost estimate.

III. PSE's AMI BUSINESS CASE DRAMATICALLY OVERSTATES BENEFITS

Q. Please describe the benefits the Company has identified in its AMI business case.

A. PSE's AMI business case identifies three sources of benefit: 1) Conservation voltage reduction (CVR), with an estimated benefit of $436 million; 2) Distribution Automation, with an estimated benefit of $1.5 million; and 3) Avoidance of the $230 million investment PSE estimated would be required to continue operating the AMR system.[17]

Q. Does Public Counsel agree with the Company's identified benefits?

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[16] Alvarez, Exh. PJA-5, PSE Response to Public Counsel Data Request No. 146, Attachment A.
[17] Alvarez, Exh. CAK-4, Appendix A at 8.

A. No.

Q. Please explain why Public Counsel does not agree with the AMI business case benefits.

A. Based on the implementation plan provided, the business case dramatically overstates the benefits customers will receive from PSE's decision to implement AMI.

Q. Please describe how PSE's AMI business case dramatically overstates benefits.

A. PSE's AMI business case overstates benefits in two ways. First, full AMI deployment is not required to secure the conservation voltage reduction (CVR) benefits which PSE attributes to AMI. PSE conducted a CVR Pilot on Mercer Island in 2013 to 2014 that included 10 circuits as part of its Distribution Efficiency initiative. In its Mercer Island CVR Pilot, PSE secured meaningful conservation benefits with just three smart meters per circuit. PSE's proposed AMI deployment involves installing smart meters at virtually every premise, an average of about 1,000 per circuit for PSE.[18] A full AMI deployment is not required to secure CVR benefits, as I discuss below.

Second, PSE counts the cost of the AMR metering system option it did not choose as a cost avoided by the AMI deployment, thereby increasing AMI benefits. However, when comparing alternatives, the avoided costs of paths not chosen are not appropriate to consider as benefits. PSE should have faithfully evaluated the costs and benefits of various metering options on a stand-alone basis, selecting the best of the options on behalf of customers. From the evidence I reviewed, PSE did not do this. Had PSE done

[18] 1,135,000 customers divided by 1,118 circuits; Alvarez, Exh. PJA-6, PSE Response to Public Counsel Data Request No. 85, subpart (d).

so, it is quite possible that PSE may have chosen the $230 million AMR continuation option over the $473 million AMI option. I summarize the amounts to be removed from PSE's estimated benefits calculation below, and discuss each in more detail.

Table 2
Overstated AMI Project Benefits

($ in millions)	
AMI Project Benefits to Customers per PSE[19]	$668.2
Less: Inappropriate attribution of CVR benefits to full AMI deployment:	(416.3)
Less: Inappropriate consideration of option cost not selected as a benefit	(230.3)
Total cost adjustments:	($646.6)
Actual AMI Project Benefits to Customers per Public Counsel:	$21.6

Q. What is Conservation Voltage Reduction (CVR)?

A Several types of customer loads, called inductive loads, use less energy at lower voltage levels. Examples of inductive loads include lighting and the heating elements of various appliances (dishwashers, electric clothes dryers, electric water and space heaters, etc.). The concept of CVR involves the reduction of voltage levels all along a circuit, so that the inductive loads all along the circuit can use less energy (the "conservation" in CVR). The challenge is that voltage falls as it travels from the source (for example, a substation) to the customers on the end of the circuit. Since electrical appliances and equipment intended for use in North America homes are designed to operate at no less than 110 volts, utilities must ensure all customers, including those at the end of the circuit, receive

[19] Koch, Exh. CAK-4, Confidential Appendix G, tab "Scope Summary", cell D79.

electricity at no less than 110 volts. The goal of CVR is to reduce voltage all along the circuit without violating the minimum 110-volt limit at the end of the circuit.

Q. Why does a utility implement CVR?

A. CVR is a conservation activity which reduces sales volumes, revenues, and profits; thus, utilities do not typically implement CVR absent a regulatory requirement to do so.

Q. Does PSE practice CVR?

A. Yes. It is my understanding that PSE has been increasing its use of CVR since completing its successful CVR Pilot on 10 Mercer Island circuits in 2013-2014. This Pilot demonstrated that energy use fell 1.09 percent with the application of CVR.[20]

Q. Explain how CVR benefits can be secured with as few as three smart meters per circuit.

A. To implement CVR, a utility needs a way to measure voltage throughout a circuit's length. With an understanding of voltage throughout a circuit, a utility is in a position to take advantage of voltage reduction opportunities while simultaneously ensuring that voltage does not drop below the 110-volt limit at the end of a circuit. While line voltage measurement devices have been available to utilities for quite some time, smart meters can measure voltage too, so some utilities implementing CVR simply employ smart meters as line voltage measurement devices. PSE used smart meters in precisely this manner in its Mercer Island CVR Pilot, installing 30 meters to measure the voltage on 10 circuits being studied for CVR effectiveness.[21] Using just three smart meters per circuit,

[20] Alvarez, Exh. PJA-7, PSE Response to Public Counsel Data Request No. 23, Attachment A at 20 (Unnamed Table), *WUTC v. Puget Sound Energy* (2018) (Dockets UE-180899 & UG-180900).
[21] *Id*. at 7 ("There are 30 meters placed on Mercer Island for the 10 feeders . . . on the island").

PSE was able to secure the 1.09 percent conservation impact cited in the Pilot results report.

Q. Do more smart meters enable greater energy reductions?

A. Yes, but only marginally so. A full smart meter deployment provides more data points reporting voltage throughout a circuit, providing utilities with more granular voltage monitoring capability and greater assurance that voltage is being delivered at a minimum of 110 volts. Closer monitoring and greater assurance of minimum voltage levels enables utilities to be more aggressive with voltage reductions, while also ensuring customer voltage remains above 110. However, the marginal improvement from full smart meter voltage monitoring as compared to more strategic smart meter placement (as demonstrated in the Mercer Island CVR Pilot) is tiny relative to the dramatic incremental costs of a full smart meter deployment, as I will explain below.

Q. What CVR-related energy reduction did PSE assume in its AMI business case?

A. PSE assumed a 1.14 percent reduction in energy use from CVR in its AMI business case.[22] This is a 4.6 percent improvement over the results from the Mercer Island CVR Pilot.

Q. Does the 4.6 percent improvement over the Mercer Island CVR Pilot results justify full deployment of AMI?

A. No. I believe this 4.6 percent improvement over the Mercer Island CVR Pilot results to be a reasonable increase in benefit for a full smart meter deployment relative to the

[22] Alvarez, Exh. PJA-6, PSE Response to Public Counsel Data Request No. 85, Attachment A, tab "Assumptions", cell C28.

strategic deployment of a few smart meters for the express purpose of implementing CVR. Again, this is due to the additional data points more smart meters provide, allowing a utility to manage voltage reductions a bit more aggressively. However, to claim all the CVR benefits from a full smart meter deployment, when 95.4 percent of those benefits could have been secured with just a few smart meters per circuit, or even a few dozen smart meters per circuit, is wholly inappropriate.

Q. Please describe your recommendation regarding PSE's CVR benefits calculation.

A. Assuming that a full smart meter benefit would deliver 4.6 percent greater energy reduction from CVR than would be the case for a limited smart meter deployment, I believe it is fair to attribute 4.6 percent of the benefits PSE estimates from CVR to a full smart meter deployment. PSE estimated the CVR benefits from a full smart meter deployment to be $436.41 million.[23] It is therefore appropriate to attribute 4.6 percent of this amount, or $20.07 million, as a benefit of a full smart meter deployment. Put another way, I believe PSE overstated the present value of CVR-related benefits from a full smart meter deployment by 95.4 percent, or by $416.34 million.

Q. Please describe the alternative options the Company evaluated for replacing its AMR system.

A. PSE evaluated three AMI options for replacing its AMR system, including deployments over six years (starting immediately), 10 years (starting immediately), and five years (but with a start in 2023 to coincide with the expiration of PSE's existing meter reading managed services contract). PSE also estimated the cost of continuing its AMR system.

[23] Koch, Exh. CAK-4, Confidential Appendix G, tab "Scope Summary", cell D77.

Q. Please describe the cost of options not selected that PSE included as a benefit in its AMI business case.

A. In its AMI business case, PSE calculated the cost to continue the existing AMR system as an alternative to an AMI deployment. However, PSE did not evaluate the benefits and costs of the AMR alternative on a stand-alone basis. Instead, it counted the cost of continuing the AMR system, which PSE ultimately abandoned, as an avoided cost benefit of the AMI deployment. Considering the continuation of the AMR system as an alternative to AMI, and counting the AMR system costs avoided as a benefit of AMI, are two entirely different things. PSE performed the latter.

Q. Does Public Counsel agree that PSE should have counted the AMR system costs avoided as a benefit of AMI deployment in the AMI business case?

A. No. Public Counsel would expect PSE to compare the costs and benefits of the AMR option to the costs and benefits of the AMI options. Instead, PSE simply categorized the avoidance of AMR costs as a benefit in its AMI business case.

PSE did not similarly categorize the avoidance of AMI costs as a benefit of an AMR deployment, which would have delivered an "apples to apples" comparison of options. An apples-to-apples comparison would have also occurred if PSE ignored the costs avoided by choosing the alternative in both AMR and AMI benefit-cost analyses. Counting the AMR costs avoided by AMI as a benefit in the AMI business case, and not counting the AMI costs avoided as a benefit of the AMR business case, does not deliver an apples to apples comparison. Yet, this is exactly what PSE did.

Q. Why is it inappropriate to consider the cost of options not selected as a benefit of the option implemented?

A. When PSE decided to implement AMI, it compared the AMI options to the most reasonable alternative, which involved the continuation of its existing AMR metering system. As PSE witness Ms. Koch explains in her testimony, the continuation of the existing AMR system would have involved an investment to replace failing gas meter data transmitters and pole mounted radios, the cost of which PSE estimated to be $230.3 million.[24] By contrast, PSE estimated the cost of its AMI deployment to be $472.7 million. From there, PSE should have compared the benefits of the AMR option less $230.3 million in AMR costs (the AMR benefit-cost analysis) to the benefits of the AMI option less $472.7 million in AMI costs (the AMI benefit-cost analysis), making the best decision for customers.

Instead, PSE counted the avoided $230.3 million AMR costs as a benefit of the AMI option. This is inappropriate. Using the same logic, I could count the $472.7 million in AMI costs avoided as a benefit of the AMR option, leading me to choose AMR by a wide margin. The convoluted logic of using avoided AMR costs as an AMI benefit represents a significant deficiency in PSE's decision-making process. Again, the standard course of action would have been to: 1) complete a stand-alone benefit-cost analysis for the AMR option; 2) complete a separate stand-alone benefit-cost analysis for the AMI option; and then 3) to compare the two benefit-cost analyses to identify the best course of action for customers.

[24] Koch, Exh. CAK-4, Confidential Appendix G, tab "Scope Summary", cell D76.

Q. How do you recommend that PSE's AMI cost-benefit analysis be corrected with respect to consideration of AMR costs?

A. I recommend removing the $230.3 million AMR option costs from the AMI benefit estimate, enabling an "apples to apples" comparison of the AMR and AMI options. By "apples to apples," I mean that in making this adjustment, the AMI benefits would no longer include the avoided AMR option costs, just as PSE's AMR cost estimate does not include the benefit of avoided AMI option costs.

Q. Please summarize your recommendation regarding PSE's overstated AMI benefits.

A. PSE's benefits calculation should be reduced by the overstated CVR benefits attributed to the full AMI deployment and the inappropriate application of a choice not selected as an avoided cost benefit. I calculate the overstated CVR benefits to be $461.3 million and the inappropriately included avoided cost is $230.3 million, for a total benefits decrease of $646.6 million. These benefit reductions, combined with the $189 million in cost additions I described earlier, paint a very different and more accurate picture of the costs and benefits of PSE's AMI deployment. The table below indicates that PSE's decision to deploy AMI was not an appropriate decision, particularly when compared to the $230 million cost of the AMR continuation option.

Table 3
Comparison of Cost-Benefit Analysis

(in millions of dollars)	Per PSE	Cost Adjust's	Benefit Adjust's	Per Public Counsel
AMI Benefits	668		(647)	21
AMI Costs	(473)	(189)		(662)
Benefits in Excess of Costs (Costs in Excess of Benefits)	195	(189)	(647)	(641)

Q. Can you summarize your assessment of the process PSE employed in making the decision to deploy AMI?

A. Given the size of the AMI investment, at almost half a billion dollars, I would expect PSE's analyses and decision-making to be beyond reproach. Instead, I have described the following fundamental deficiencies in PSE's AMI decision process in this testimony:

- PSE did not consider $189 million of abandoned equipment cost customers must pay in making its decision;
- PSE attributed $416 million in CVR benefits to its full AMI deployment, even though PSE's own CVR Pilot indicated it could have secured these benefits through selective smart meter placement at a dramatically lower cost;
- PSE did not conduct a stand-alone cost-benefit analyses for the AMR continuation option, further biasing its decision to install AMI.

Based on the fundamental nature of these deficiencies, as well as the implementation plan provided in the AMI business case, I conclude that PSE's evaluation of metering options was flawed. These flaws resulted in a choice which grew the rate base the most, rather than a choice in the best interests of customers. The flaws also cause me concern about PSE's overall distribution grid and business investment vetting and decision-making process. I turn to this concern in the next section of testimony.

IV. SUMMARY OBSERVATIONS AND IMPLICATIONS

Q. Do you have any summary observations regarding PSE's AMI decision process?

A. Yes. The flaws I observed in PSE's AMI business case are consistent with themes I have identified in dozens of grid modernization plan and project evaluations I have completed over the last nine years. These themes include: 1) investor-owned utilities (IOUs) have a financial incentive to grow their rate bases; 2) IOU analyses are biased in favor of capital-intensive solutions; and 3) once the assets are installed, interest in maximizing economic benefits on behalf of customers – particularly those customer benefits which harm IOU financial results -- is extremely low.

In my appearances before regulators, in both formal and informal settings, I always try to communicate the notion that modern grid investments are different than traditional grid investments. While the focus was formerly concerned with accommodating load growth, modern grid investments are intended to produce other outcomes. In my experience, associated successes are both highly variable from utility to utility, and entirely dependent on the post-deployment actions of utilities, regulators, and customers.

Q. What do you suggest?

A. Regulators across the U.S. are evaluating current ratemaking processes. Post-deployment rejection of recovery on large investments presents a regulatory conundrum. If cost recovery for inappropriate decisions is approved, inappropriate decision-making is encouraged, and customer rates increase. If cost recovery for inappropriate decisions is disallowed, particularly in the case of large investments, IOU risk and capital costs increase, and customer rates increase anyway. While I would never suggest that the prudence of utility investments should be determined in advance, I believe the regulatory conundrum illustrates the benefits of increased regulatory involvement, stakeholder engagement, and transparency in IOU investment decisions before capital is spent, in addition to the prudence review that occurs after capital is spent.

Q. Please explain how the complexities of electricity distribution can be subject to greater transparency, regulatory involvement, and stakeholder engagement?

A. We already have a template to follow in resource planning. Two to three decades ago, stakeholders had no idea what resource planning was, or how their input could be valuable. Today, stakeholder engagement in resource planning is the norm in states with vertically-integrated electricity markets, such as Washington. There are similarities between distribution investment planning processes and generation investment planning processes.

Commission review of investment plans with stakeholder participation will better align grid investments and capabilities with Commission, state, and community priorities, and deliver a better cost-benefit-risk profile for both customers and IOUs. PSE's $473 million decision to invest in AMI without considering the $189 million cost customers would pay for abandoned equipment is a symptom of greater problems. The fact that PSE justified its $473 million AMI decision with CVR benefits it could have secured at a fraction of the cost is a symptom of greater problems. PSE's failure to complete stand-alone cost-benefit analyses of the AMR continuation option for objective comparison is a symptom of greater problems. I strongly encourage the Commission to consider stakeholder engagement in advance of grid investment as a reasonable approach to mitigating the problems inherent in current ratemaking processes.

Q. Is there precedent for stakeholder engagement in utility planning and capital budgeting in Washington?

A. Yes. The Commission's integrated resource planning process is analogous to what I am recommending. I understand that in Washington, regulated electric utilities present plans to meet generation capacity needs to stakeholders. As in other jurisdictions, such plans include all analyses used to demonstrate the need for new generating capacity, evaluations of multiple alternative approaches to securing needed generating capacity, and so on. Stakeholders are able to ask questions, and provide feedback and input, which the utilities use to develop a final plan for the Commission. This is not an advance determination of prudence, but an acknowledgement by the Commission that the utility has complied with integrated resource planning requirements.

V. REVIEW AND RECOMMENDATIONS

Q. Please review your testimony.

A. My testimony demonstrates that the incremental cost of PSE's AMI deployment will exceed the benefits to customers by a wide margin ($641 million), and that AMR continuation would have been a less costly option to secure the types of outcomes PSE claims from AMI. Conservation voltage reduction benefits could have been secured through selective smart meter placement rather than full AMI, and the problems with the existing metering system could have been resolved at a cost of only $230 million (PSE's own estimate).

My testimony also demonstrates that changes in the nature of distribution grid and business investments warrants stakeholder input before capital is spent. Due to their large size, disallowance of imprudently-incurred grid modernization costs is an increasingly unfeasible decision for regulators. Yet, due to inherent variability in post-deployment benefits, pre-approval of grid investments is not advised either. I suggest that future grid investment decisions in Washington be guided by increased regulatory review, stakeholder engagement, and transparency.

Q. Based on this testimony, what are your recommendations to the Commission?

A. I recommend the Commission disallow cost recovery of and on capital PSE spent to implement its AMI system on the basis of imprudence. Public Counsel witness Mark Garrett provides testimony regarding the revenue requirement adjustment amount of the disallowance and the revenue requirement impact. My conclusion that PSE's AMI investment was imprudent is based on the following facts:

- PSE did not consider the $189 million cost of abandoned equipment customers must pay in making its decision;
- PSE attributed $416 million in CVR benefits to its full AMI deployment, even though PSE's own CVR Pilot indicated it could have secured these benefits through selective smart meter placement at a fraction of the cost;
- PSE did not conduct stand-alone benefit-cost analyses on the various metering options available, further biasing its decision to install AMI;

- After making adjustments for these analytical deficiencies, customers will pay $641 million for the AMI investment, whereas the alternative fixes to PSE's existing AMR system would have only cost $230 million.

Unless and until PSE can show that the benefits to customers of the AMI deployment exceed the deployment's costs, the investment should not be included in customer rates. If the Commission disagrees, and approves PSE's AMI deployment for cost recovery, I recommend the Commission disallow cost recovery for the $126.8 million in book value of the existing metering system replaced prematurely. This would eliminate the violation of the used and useful principle by avoiding simultaneous customer payments for two metering systems, both the new system and the undepreciated legacy system replaced as a result of a discretionary decision by PSE. Appropriate accounting for this option would involve writing the book value of the existing metering system down to zero with the offset being a reduction in PSE income, perhaps as an extraordinary expense.

I also recommend that the Commission establish a proceeding to consider how to improve the distribution investment decisions of Washington's regulated utilities through the implementation of a transparent, stakeholder-engaged distribution planning and capital budgeting process under regulatory review. By "improve," I mean to increase the alignment of utility distribution investment decisions with state, community, and customer goals. Resource planning process experience could help inform the design of a distribution planning and capital budgeting process which includes stakeholders.

Q. Does this conclude your testimony?

A. Yes, it does.