**STATE OF NEW JERSEY**
**OFFICE OF ADMINISTRATIVE LAW**
**BEFORE THE HONORABLE IRENE JONES**

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| **IN THE MATTER OF THE VERIFIED PETITION OF ROCKLAND ELECTRIC COMPANY FOR APPROVAL OF CHANGES IN ELECTRIC RATES, ITS TARIFF FOR ELECTRIC SERVICE, AND ITS DEPRECIATION RATES, AND FOR OTHER RELIEF** | **)<br>)<br>)<br>)<br>)<br>)<br>)** | BPU DOCKET NO. ER19050552<br>OAL DOCKET NO. PUC07548-2019 |

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**DIRECT TESTIMONY OF**
**PAUL J. ALVAREZ**
**ON BEHALF OF THE**
**DIVISION OF RATE COUNSEL**

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# DIRECT TESTIMONY OF PAUL J. ALVAREZ

## I. INTRODUCTION, QUALIFICATIONS, PURPOSE, AND PREVIEW

**Q. Please state your name and business address.**

A. My name is Paul J. Alvarez. My business address is 6483 Big Horn Trail, Littleton, CO 80125.

**Q. What is your occupation?**

A. I am the President of the Wired Group, a consultancy specializing in the optimization of distribution utility businesses and operations as they relate to grid modernization (including smart meters), demand response, energy efficiency, and renewable generation.

**Q. On whose behalf are you submitting testimony?**

A. I am testifying on behalf of the New Jersey Division of Rate Counsel (DRC).

**Q. Please describe your work experience and educational background.**

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] Alvarez et al, MetaVu. "SmartGridCity™ Demonstration Project Evaluation Summary". Report submitted to the Colorado Public Utilities Commission in the testimony of Michael G. Lamb, Exhibit MGL-1, proceeding 11A-1001E. Report dated October 21, 2011; 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 Northwestern University in 1991. Both degrees featured concentrations in Finance and Marketing.

[2] Alvarez et al, MetaVu. "Duke Energy Ohio Smart Grid Audit and Assessment". Report to the Staff of the Public Utilities Commission of Ohio in proceeding 10-2326-GE-RDR. June 30, 2011.

**Q. Have you appeared before the New Jersey Board of Public Utilities previously?**

A. No.

**Q. What experience do you have before other state utility regulatory commissions?**

A. I have testified in, or served as a consultant to clients in support of, cases before state utility regulatory commissions on smart meters, associated rate designs, grid modernization, distribution planning processes, and distribution utility performance measures in 20 different states in dozens of cases in the last five years. Brief descriptions of submitted testimony or reports, and case numbers for each, are provided in the "Regulatory Appearances" section of my Curriculum Vitae, attached as Appendix A.

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

A. I provide testimony regarding the cost-effectiveness of Rockland Electric Company's (RECO) Advanced Metering Infrastructure (AMI) deployment. I examined the actual costs and benefits of RECO's AMI deployment through extensive discovery, and found that the costs to customers of RECO's AMI project will far exceed the benefits to customers as presently planned. Furthermore, I found that RECO's request for AMI cost recovery violates the well-established "used and useful" regulatory principle. My testimony is organized as follows:

- The cost to customers of RECO's AMI deployment will be significantly greater than RECO projected in its AMI business case;

- The benefits to customers of RECO's AMI deployment will be significantly less than RECO projected in its AMI business case;
- The costs to customers of RECO's AMI deployment dramatically exceed the benefits to customers;
- RECO's proposed request for AMI cost recovery violates the well-established "used and useful" regulatory principle.

**Q. Before you present these arguments, can you please provide your overall impression of the state of AMI in the United States today?**

A. My research indicates that the benefits from AMI deployments vary widely from utility to utility based on the types of programs utilities implement and the design of those programs. As with utility demand-side management programs, my research suggests that no AMI or grid modernization plan should proceed without 1) a clear plan to maximize available benefits; 2) a clear understanding of conservatively-estimated customer costs and customer benefits; and 3) a clearly-defined benefit measurement program. Maximizing the customer benefits from an AMI deployment in a manner sufficient to exceed costs to customers requires extensive post-deployment efforts from all parties, including utilities, regulators, and customers. To summarize, and as this testimony will indicate, operating expense reductions alone are insufficient for AMI deployments to deliver benefits in excess of costs to customers.

## II. AMI COSTS TO CUSTOMERS WILL BE SIGNIFICANTLY HIGHER THAN RECO PROJECTED IN ITS BUSINESS CASE

**Q. Please describe your efforts related to RECO's AMI Business Case**

A. I have carefully examined the cost and benefit projections RECO provided in its original AMI Plan,[3] as well as an update provided in discovery in this case. I note that the update involved just one issue: in the 3 years that have elapsed since RECO developed its original cost and benefit projections, customers have been paying a return of (and on) capital for the legacy meters removed from service to make way for AMI meters. As a result, RECO alleges the cost of the project has fallen, as the book value of legacy meters is now smaller. While I think this is disingenuous, because customers have been paying depreciation for the past three years, I note a broader concern. That is, that RECO has not updated the AMI Plan for actual costs and actual benefits. If I were the Board, I'd be interested to know why. I believe that a negative inference should be drawn from the failure to update, since presumably RECO would have updated the business plan if an update would have been to its benefit.

**Q. Please explain why AMI Costs to Customers will be significantly higher than RECO projected in its business case.**

A. I have identified deficiencies that will require customers to pay significantly more than the amount projected. Primary among these is the fact that carrying charges customers will pay, on both the new AMI meters and systems as well as on legacy

[3] BPU ER16060524.

meters removed from service prematurely, are missing from RECO's cost projections. I have estimated these costs, and found them to be significant. I have other concerns about RECO's projected costs which I have not quantified, but which are likely to increase customer costs in future years.

**Q. What are carrying charges, and why do customers have to pay them?**

A. Carrying charges include authorized profits on invested capital, state and federal income taxes on those profits, and interest expense on capital. If customers do not pay these costs, for-profit utilities like RECO will have no opportunity to earn profits on used and useful investments, and would therefore have no incentive to make any investments. Customer payment of carrying charges is a critical part of the regulatory compact under which all for-profit utilities in the United States operate.

**Q. Why should RECO have included carrying charges in its cost projections?**

A. The benefit projections in RECO's business case were estimated on the basis of benefits to customers. Meanwhile, RECO did not use costs to customers in its analysis, but instead used costs internal to RECO. To provide an "apples-to-apples" comparison, RECO's business case should have compared customer benefits to customer costs, not RECO's costs. As carrying charges are part of what customers must pay, carrying charges should have been included in RECO's customer cost projections for comparison to customer benefits in RECO's business case.

**Q. Have you estimated these carrying charges?**

A. Yes. I estimate the carrying charges on the $16.5 million in AMI capital RECO projects in its business case to be $14.945 million over 20 years (RECO's proposed useful life for AMI meters). My estimation took into account, for purposes of this calculation only, RECO's requested return on equity (9.6%), current interest rates (5.89%), federal and state income tax rates (30% combined); and debt-to-equity ratio (50.3%) as shown in Appendix B. In addition to depreciation and carrying charges on AMI capital, RECO requests depreciation and carrying charges[4] on legacy meters removed from service prematurely (to make way for AMI meters).[5] I estimate additional carrying charges on the $5.2 million book value of legacy meters to be $3.813 million over 15 years using the same assumptions listed above, also shown in Appendix B. Thus, in total, RECO has underestimated the cost to customers of its AMI plan by $18.758 million in carrying charges – an 86% mis-statement on $21.745 million in projected capital costs.

**Q. What other concerns do you have regarding RECO's cost estimates?**

A. Most utilities depreciate smart meters over 15 years, a reflection of the expected useful life of a smart meter. Most utilities' smart meter business cases estimate benefits over 20 years, rather than 15 years, under the assumption that many if not half or more of smart meters will last longer than 15 years. I generally recommend rectifying this discrepancy by shortening the business case benefit period to 15 years,

[4] BPU ER19050552. RECO response to RCR-REV-INF-2.
[5] I note that charging customers a return on and of capital for both new and retired assets simultaneously is a violation of the used and useful regulatory principle, which I will address later in my testimony.

thereby matching the benefit period to smart meter expected useful life. RECO rectifies the discrepancy by extending the smart meter useful life from 15 years to 20.

While the RECO approach eliminates the discrepancy (and over-estimates benefits in the process), it ignores the fact that smart meters will probably start failing in increasing numbers towards the end of the 20-year business case period. The same is true for AMI field communication network devices, which generally have a shorter useful life than smart meters. Yet despite this anticipated increase in equipment failure rates in the latter years of the business case, RECO's cost estimates make no provision for AMI meter or communications device replacements in business case years 16-20. RECO cannot have it both ways. The business case should either 1) reflect a 15-year benefit period corresponding to the estimated useful life of AMI meters and communications equipment most utilities use; or 2) include costs for equipment replacement in years 16-20. RECO's business case does neither.

## III. THE BENEFITS OF AMI FOR CUSTOMERS WILL BE SIGNIFICANTLY LESS THAN RECO PROJECTED IN ITS BUSINESS CASE

**Q. Please explain why the benefits of AMI for customers will be significantly less than RECO projected in its business case.**

**A.** I have carefully examined the AMI benefit projections in RECOs AMI business case, and compared those projections to historical operating expense data and RECO's operating expense reduction plans obtained in discovery. I have identified several deficiencies in RECO's benefit estimation methodologies which severely over-estimate the economic benefits RECO's AMI deployment will deliver. These include:

1) RECO utilized "rules of thumb" which included fixed overheads when estimating the current costs which would be avoided by AMI, thus severely over-estimating the variable costs reductions AMI could deliver;

2) RECO counted "strategic management of resources to other tasks" as customer benefits despite zero or limited headcount reductions in business functions;

3) RECO over-estimated the capital it was spending to replace old meters, severely over-estimating the benefit of avoided meter replacement costs.

**Q. How did RECO's use of "rules of thumb" in benefit projections severely over-estimate the economic benefits the AMI deployment could deliver?**

A. RECO used many "rule of thumb" employee hourly rates when calculating AMI benefit projections in its business case. I would expect these hourly rule of thumb rates to include labor and fringe benefits. But RECO's rules of thumb hourly rates include fixed overhead costs which will not fall when a headcount, for example in the meter reading function, is reduced. Examples of fixed overhead costs RECO included in its rule of thumb hourly rates include allocations of fixed costs like indirect labor, service center overhead, corporate overhead, and management overhead. These fixed overhead costs will remain when headcounts fall, so any inclusion of such costs in benefit projections will overstate the savings an AMI deployment an actually deliver.

**Q. Can you provide any illustrative examples?**

**A.** I can provide several, beginning with meter reading. From information obtained in discovery, I learned that the average meter reader earns $24.67 per hour. On top of that, the rule of thumb adds $4.46 in indirect labor, $10.39 in service center overhead, $24.44 in management overhead, and $2.14 in corporate overhead. I would not expect any of these costs to fall with a reduction in meter reader headcount. The fringe benefit rate is applied to all of these hourly rate components, not just salaries, adding an additional $29.27 per hour, some of which probably covers fixed costs which will not fall with headcount reductions. I contend that RECO should have utilized, at most, an hourly estimated savings per meter reader of $53.94 per hour ($24.67 in wages plus $29.27 in fringe benefits). Instead, RECO included all the fixed overheads which will not fall with meter reader reductions in its rule of thumb savings rate of $95.37 an hour.[6] Multiplied by 2,080 hours per headcount in a year, RECO projected meter reader savings from AMI at $198,370 per meter reader, per year. But clearly, RECO's costs will not fall $198,370 annually for each meter reader reduction.

[6] BPU ER19050552. RECO response to DR RCR-AMI-46, Worksheet tab "MR".

**Q. Why wouldn't you expect indirect and overhead costs to fall with reductions in meter reading labor?**

A. All introductory accounting and finance textbooks define indirect and overhead costs as the cost associated with running a business which cannot be linked to a specific product or service. Let's look at the examples I provide above. RECO's "rule of thumb" hourly rate includes $10.39 per hour of labor for service center overhead, but service center costs (operations, maintenance, property taxes, etc.) will not fall with a reduction of nine meter readers. The rule of thumb hourly rate includes $24.44 for management overhead, likely from meter reading up to the ConEd COO, but this chain of command is not likely to change much with a reduction of nine meter readers. Corporate overhead, from accounting and finance to human resources and regulatory affairs, will not change with a reduction of nine meter readers.

That a $198,370 annual benefit estimate per meter reader, which incorporates fixed overheads, is far too high is borne out in a macro analysis of accounting data. Because nine RECO meter reader headcounts would be reduced from AMI, RECO multiplied $198,370 by 9 to estimate an annual customer benefit from AMI-related meter reader reductions at $1.785 million per year.[7] However, Orange and Rockland's combined meter reading department expense in 2017 was $6.187 million,[8] of which RECO's share per the 2017 Joint Operating Agreement (JOA) was only 18.5%,[9] or $1.147 million. It is impossible for RECO's AMI deployment to

[7] BPU ER19050552. RECO response to RCR-AMI-16, Worksheet tab "RCR-AMI-d", cell F22.
[8] BPU ER19050552. RECO response to RCR-AMI-47, Worksheet tab "2017.C", cell O12.
[9] BPU ER19050552. RECO response to RCR-REV-INF-03; also S-RECO-JOA-1 2017 Common Exp. Splits.

generate 64% more in meter reading expense reductions ($1.785 million) than RECO's actual meter reading expense prior to the AMI deployment ($1.147 million).

Data collected in discovery provides several additional examples. RECO estimated that every hour reduced in meter operations would benefit customers by $118.13 per hour, while the average meter operations technician earns just $30.55 per hour and $36.26 per hour in fringe benefits.[10] Perhaps the most aggressive estimate I found was in electric operations, for which RECO claims AMI will deliver reduced costs through fewer dispatches to investigate false outages as one example. While the average lineman earns $51 an hour, and fringe benefits are $95.28 per hour (seems very high and likely includes many fixed overhead costs), the lineman rule of thumb rate is $302 per hour.[11] Worse, RECO's benefit estimates assume all service calls require a 2-man crew, even though RECO does not always deploy a 2-man crew,[12] for an estimated customer benefit of $604 per hour of crew time reduced. At this rate, RECO would be assuming that the reduction of a single 2-man crew will deliver a customer benefit of $1.256 million per year ($604 per hour multiplied by 2,080 hours). Thus, the use of rules of thumb with embedded fixed costs clearly led to greatly exaggerated customer benefit projections in RECO's AMI business case.

[10] BPU ER19050552. RECO response to RCR-AMI-46, Worksheet tab "CFT"
[11] BPU ER19050552. RECO response to RCR-AMI-46, Worksheet tab "OH".
[12] BPU ER19050552. RECO response to RCR-AMI-64.

**Q. Have you estimated the size of the excess benefit projections?**

**A.** I have estimated the excess benefit projections for meter reading. I did not adjust benefit projections in the other department examples to avoid double counting benefit estimate reductions in these departments I make for other reasons, which I will describe after answering this question.

In place of using RECO's annual meter reading benefit estimate, I recommend using a variable cost reduction approach. I estimate the actual benefits customers will receive by isolating the variable costs associated with meter readers (labor and fringe benefits) and multiplying by headcount reductions and annual labor hours per head:

($24.67/hr. + $29.27/hr.) x 9 heads x 2,080 hrs/head/yr. = $1.010 million/yr.

I have high confidence in this benefit estimate, as it is about 88% of the 2017 Orange and Rockland (O&R) meter reading expense multiplied by the appropriate 2017 RECO cost allocation per the JOA ($1.147 million as mentioned earlier). In my experience, a 100% meter reading expense reduction from AMI is not possible, as 10% or more of meter reading expenses generally remain once AMI has been deployed (for example, to cover reading meters of AMI opt-out customers manually). I would question any meter reading savings projections amounting to more than 90% of historical actual meter reading department spending.

I estimate that the actual meter reading benefit from AMI will be $776,000 less per year than RECO estimates. Employing RECO's assumptions for a gradual meter reader reduction over the 2-year AMI deployment period and a 2% annual cost escalation rate, I calculate the benefit to customers from meter reading headcount reductions to be only \$23.678 million over 20 years, \$18.226 million less than RECO's estimate of \$41.904 million. The details of this calculation are provided as Appendix C, incorporated into this testimony by this reference.

**Q. Describe how RECO counts "strategic management of resources to other tasks" as expense reductions, and how you believe this artificially inflates the customer benefits RECO projected in its AMI business case.**

A. While the incorporation of fixed overheads into "rule of thumb" costs used to project benefits greatly exaggerates benefit projections, RECO also exaggerates benefit projections in other ways. The most impactful of these is to equate reductions in levels of effort, such as less time spent on customer reconnect/disconnects (meter operations department savings), or less time spent restoring outages (electric operations department savings), as customer economic benefits. This would be reasonable for RECO to assume if headcount reductions were to result from reductions in levels of effort. However, in discovery, I found headcount reduction plans to be zero in two business functions, and woefully short of the levels required to deliver the economic benefits to customers RECO projects in its AMI business case in another. Upon further inquiry it became clear that RECO's AMI business case assumed that "strategic management of resources to other tasks"[13] should count as an economic customer benefit despite zero or limited headcount reductions and, therefore, zero or limited rate reductions.

[13] BPU ER19050552. RECO responses to RCR-AMI-40(b) and RCR-AMI-68.

**Q. Can you provide examples?**

**A.** In its business case RECO assumes $577,000 in customer benefits annually, and $13.5 million in customer benefits over 20 years, in the electric operations function (linemen).[14] Yet RECO/O&R have no plans for any headcount reductions in the electric operations department as a result of the AMI deployment.[15] In its business case RECO assumes $91,000 in customer benefits annually, and $2.1 million in benefits over 20 years, in the customer service function.[16] Yet RECO/O&R have no plans for any headcount reductions in the customer service department as a result of the AMI deployment.[17] In its business case RECO assumes $492,378 in customer benefits annually, and $11.5 million in customer benefits over 20 years, in the meter operations department.[18] Yet just three headcount reductions in meter operations are planned for all of O&R,[19] making RECO's headcount reduction share just one-half of a head (three reductions x 16.6% 2019 JOA allocation).[20] Using the same methodology I employed above to calculate actual meter reading benefits based on variable meter reading costs (labor plus fringe benefits), I estimate the actual meter operations department benefit to RECO customers will be only $69,000 annually:

(**$**30.55/hr. labor + $36.26/hr. benefits) x 1/2 head x 2,080 hrs/head/yr. = $69,482/yr.

[14] BPU ER19050552. RECO response to RCR-AMI-16, Worksheet tab "RCR-AMI-16.d", cells F47 to G49.
[15] BPU ER19050552. RECO response to RCR-AMI-40 (a).
[16] BPU ER19050552. RECO response to RCR-AMI-16, Worksheet tab "RCR-AMI-16.d", cells F7 and G7.
[17] BPU ER19050552. RECO response to RCR-AMI-68.
[18] BPU ER19050552. RECO response to RCR-AMI-16, Worksheet tab "RCR-AMI-16.6", cells F25 to G33.
[19] BPU ER19050552. RECO response to RCR-AMI-59 (a).
[20] BPU ER19050552. S-RECO-JOA-1 2019 Common Exp. Splits.

**Q. How much less do you believe actual AMI customer benefits will be when actual headcount reductions are used to calculate AMI-related savings?**

A. I believe "level of effort" reductions in electric operations and customer care which are not supported by any corresponding headcount reductions should be eliminated entirely from RECO's AMI benefit projections. Over 20 years, these reductions amount to $13.540 million and $2.137 million, respectively. To those eliminations I would add reductions in meter operations benefits as described immediately above. Over 20 years, following RECO assumptions for a gradual meter operations headcount reduction over the 2-year AMI deployment and a 2% annual cost escalation rate, I calculate the meter operations benefit to customers to be only $1.6 million over 20 years, $9.9 million less than RECO's estimate. (The details of this calculation are provided in Appendix C.) When combined with the elimination of benefits in electric operations and customer care, I calculate a total benefit reduction from a lack of headcount reductions at $25.605 million (the difference between RECO's $27.234 million benefit estimate and my benefit estimate of $1.629 million) over 20 years as indicated in the table below:

| ($ in 000's) | Annual per RECO | Annual per DRC expert | Annual difference | 20-year per RECO | 20-year per DRC expert | 20-year difference |
|---|---|---|---|---|---|---|
| Electric Operations | $577 | $0 | ($577) | $13,540 | $0 | ($13,540) |
| Customer Care | 91 | 0 | ($91) | 2,137 | 0 | (2,137) |
| Meter Operations | 492 | 69 | (423) | 11,557 | 1,629 | (9,928) |
| Totals | $1,160 | $69 | ($1,091) | $27,234 | $1,629 | (25,605) |

**Q. Explain how RECO over-estimated the capital it was spending to replace old meters, and how this led to over-estimated customer benefits in the AMI business case.**

A. The meters RECO was using prior to the AMI deployment were obviously older than the new meters. It is not surprising that RECO was spending capital to replace these older meters as they failed. It is also reasonable for RECO to assume, at least for 15 years or so, that the new meters it would be installing would result in a dramatic reduction in the capital required for meter replacement relative to historical experience. New meters would not be expected to fail, and therefore would require no replacement capital, until they began to reach the end of their expected useful lives as I testified earlier. In discovery, RECO reported its historical experience on replacement meter capital. In the three years immediately preceding the AMI deployment, RECO spent an average of $49,333 in capital annually to replace old meters as they failed.[21] However, in its business case, RECO assumed that the benefit resulting from a reduction in annual meter replacement capital would be $360,000 annually,[22] or more than seven times larger than RECO's historical experience.

Clearly, RECO's AMI deployment will not be able to reduce meter replacement capital by a factor of seven times historical spending levels. Using RECO's historical experience to estimate future capital savings, and adding an annual cost escalation for inflation of 2%, I estimate the savings from avoided meter capital over 20 years will be only $1.2 million, a $5.6 million reduction from the 20-year estimate in RECO's business case of $6.9 million. The details of this calculation are provided in Appendix C.

## IV. THE COSTS TO CUSTOMERS OF RECO'S AMI DEPLOYMENT WILL DRAMATICALLY EXCEED CUSTOMER BENEFITS

**Q. You have testified that RECO's AMI business case substantially under-estimated costs to customers, and substantially over-estimated customer benefits. Given the actual costs to customers and actual customer benefits you estimate, will the customer benefits of RECO's AMI deployment exceed customer costs?**

[21] BPU ER19050552. RECO response to RCR-AMI-55.
[22] BPU ER19050552. RECO response to RCR-AMI-16, Worksheet tab RCR-AMI-16.d, cell J15.

A. No. The costs to customers of RECO's AMI deployment will far exceed the benefits of the deployment as planned. Let's start with costs. RECO projected the total cost of its AMI deployment, including capital and operating expenses, would be $33.785 million over 20 years. However, as I testified earlier, this figure does not include the carrying charges on capital customers must pay, including authorized profits, income taxes on profits, and interest expense, of $18.758 million over 20 years. Thus, the total costs of the AMI deployment to RECO customers over 20 years will be $52.543 million, not $33.785 million, or 56% greater than RECO projected in its AMI business case.

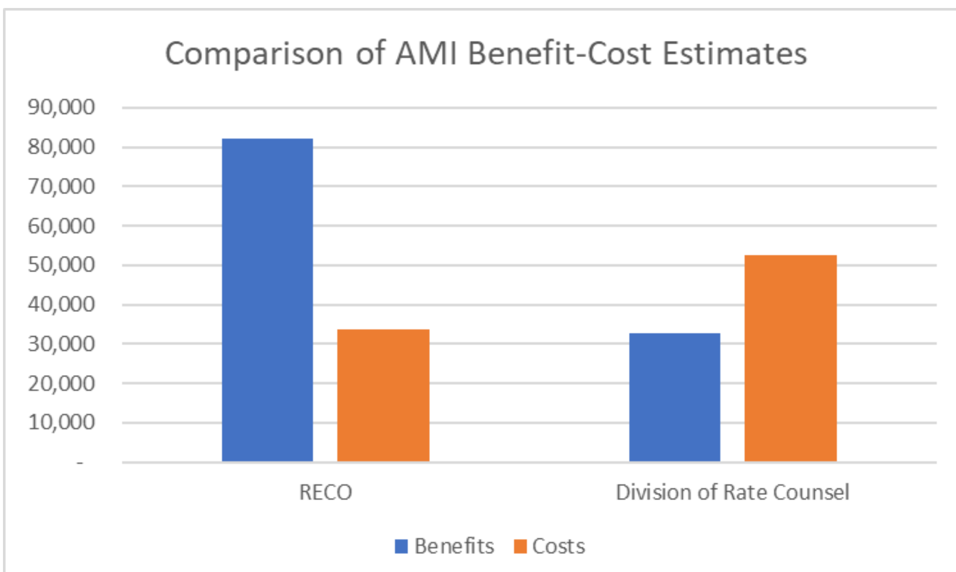
Regarding benefits, I provided details above indicating that the actual benefits to customers from RECO's AMI deployment will be dramatically less than RECO projected. I estimate that actual benefits to customers will be at least $49.477 million less (60%) than RECO projected in its AMI business case:

| | | |
|---|---|---|
| RECO Projected Benefits, 20 Years | | $82.037 MM |
| Meter Reading savings in excess of historical actual spending: | ($18.226 MM) | |
| O&M savings projections not backed by headcount reductions: | ($25.605 MM) | |
| Avoided meter replacement capital in excess of historical actual spending: | ($ 5.646 MM) | |
| Total reductions in projected benefits: | | ($49.477 MM) |
| Actual benefits expected per the DRC Expert: | | $32.560 MM |

**Q. Please present these adjustments in tabular and chart formats.**

A. Whereas RECO projected that customer benefits would exceed costs by almost $50 million, I calculate that customer costs will exceed customer benefits by almost $20 million, a $70 million swing:

| ($ in millions) | RECO | Division of Rate Counsel |
|---|---|---|
| **Customer Benefits** | $82.037 | $32.560 |
| **Customer Costs** | 33.785 | $52.543 |
| **Excess (Deficit)** | $48.252 | (19,983) |



## V. RECO'S PROPOSED REQUEST FOR AMI COST RECOVERY VIOLATES THE WELL-ESTABLISHED "USED AND USEFUL" REGULATORY PRINCIPLE

**Q. Please describe the used and useful principle and its purpose.**

A. The used and useful principle has been used by monopoly utility regulators to protect consumer interests for many decades. Though the used and useful principle first evolved in the 1940s, in 1980 the D.C Circuit Court of Appeals clarified ". . . an item may be included in rate base only when it is 'used and useful' in providing service."[23] The used and useful principle prevents investor-owned utilities ("IOUs") from growing profits by investing more in physical assets than is necessary to serve customers. Regulators can deny cost recovery from customers for IOU investments which are not "used and useful," thereby discouraging unnecessary IOU investment and protecting consumers from unnecessary cost increases.

**Q. Why do you believe RECO's request for AMI cost recovery violates the used and useful principle?**

**A.** The installation of new AMI meters "en masse" (i.e., for all customers) involved the removal and retirement of existing meters (legacy meters). RECO reports that these legacy meters have a book value of $5.2 million. In its application, and as one would expect, RECO asks for recovery of and on capital for its new meters and all associated investments (the meter communications network, software, etc.).[24] In

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[23] Tennessee Gas Pipeline Co. v. FERC, 606 F.2d 1094, 1123 (D.C. Cir. 1979), cert. denied, 445 U.S. 920 and 447 U.S 922 (1980)
[24] BPU ER19050552. RECO response to RCR-AMI-33.

addition, RECO asks the Board for permission to categorize the book value of the legacy meters as a regulatory asset, and to recover a return on and of capital costs associated with these meters over 15 years.[25] Thus, for the next 15 years, RECO customers will be paying for two sets of meters simultaneously. This is a clear violation of the used and useful principal, as the legacy meters are not being used. They have been taken out of service.

## VI. SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

**Q. Please summarize your testimony.**

A. My testimony supports the following conclusions:

- The cost to customers of RECO's AMI deployment will be at least $18.758 million higher than RECO projected in its business case;
- The benefits to customers of RECO's AMI deployment will be at least $49.477 million lower than RECO projected in its business case;
- As a result, RECO's AMI deployment is not cost effective, with the costs of the deployment exceeding the benefits to customers by $19.983 million;
- RECO's proposal to simultaneously recover costs on both the AMI deployment and legacy meters removed from service violates the well-established "used and useful" regulatory principle.

[25] BPU ER 19050662. RECO Depreciation Panel testimony, page 23; RECO response to RCR-REV-INF-02.

**Q. Given your testimony, what do you recommend to the Board of Public Utilities?**

**A.** Given that the cost to customers of RECO's AMI deployment exceeds benefits by a wide margin, I recommend the Board reject RECO's request for recovery of and a return on the capital RECO spent on its AMI deployment. Should the Board disagree, I believe, at a minimum, that the Board should reject RECO's request for a return of and on the book value of legacy meters removed from service prematurely to make way for AMI meters, as cost recovery of both AMI and legacy meters simultaneously violates the used and useful principle.

**Q. Is there precedent for this among US state utility regulators?**

**A.** Yes. In 2010, the Maryland PSC ordered cost recovery deferral until utilities' AMI deployments could be proven cost-effective for customers.[26] More recently, in 2018, state utility regulators in Kentucky,[27] Massachusetts,[28] and New Mexico[29] prospectively (i.e., before deployment) rejected AMI deployments on the basis that customer costs were likely to exceed customer benefits. Though these were not deferrals or rejections of cost recovery requests, they indicate that state utility regulators are increasingly skeptical of AMI deployment benefits, and are appropriately requiring AMI deployments to demonstrate customer benefits in excess of customer costs.

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[26] Maryland PSC 9207 and 9208. Orders 83532 and 83521, respectively, dated August 13, 2010.
[27] Kentucky PSC 2018-00005. Order dated August 30, 2018.
[28] Massachusetts DPU 15-120, 15-121, and 15-122. Order dated May 10, 2018.
[29] New Mexico PSC 15-00312-UT. Order dated March 19, 2018.

**Q. Do you offer any other support for your recommendations?**

A. Yes. In summary:

- It is puzzling why RECO has chosen to rely on stale data contained in its original AMI business case, rather than update for actuals. It is my understanding that the Board was looking for actual data in support of the Company's Petition.
- RECO has failed to demonstrate that the benefits of AMI outweigh the costs,
- Because RECO has failed to show that the benefits of AMI outweigh the costs, RECO has not demonstrated that its investment in AMI was reasonable and prudent.

**Q. Does this conclude your testimony?**

A. Yes, it does. However, I respectfully request the right to append this testimony based on testimony submitted by Staff and other intervenors in this proceeding.

# APPENDIX A

# APPENDIX A: CURRICULUM VITAE OF PAUL J. ALVAREZ

## Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed the limitations of current utility regulatory and governance models. Mr. Alvarez currently serves as the President of the Wired Group, a boutique consultancy serving consumer and environmental advocates, regulators, associations, and suppliers.

## Appearances and Research Projects in Regulatory Proceedings

**Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light.** Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan ($1.2 billion) based on benefit-cost analyses of plan components. Cause 45264. October 7, 2019.

**Investigation into Distribution Planning Processes.** Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

**Investigation into Grid Modernization.** Comments to the New Hampshire Public Utilities Commission recommending a transparent, stakeholder-engaged distribution planning process. IR 15-296. September 6, 2019.

**Arguments to Reduce and Re-prioritize Grid Modernization Investments Proposed by Pacific Gas & Electric.** Testimony before the California Public Utilities Commission. A.18-12-009. July 26, 2019.

**Evaluation of Xcel Energy's Request for an Advance Determination of Prudence Regarding Natural Gas Generation Plant Purchase.** Testimony before the North Dakota Public Service Commission. PU-18-403. May 28, 2019.

**Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement.** Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

**Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding.** Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

**Evaluation of Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources.** Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

**Evaluation of Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan.** Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

**Evaluation of National Grid's Massachusetts Smart Meter Deployment Plan.** Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017.

**Evaluation of Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources.** Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

**Recommendations on Metropolitan Edison's Grid Modernization Plan.** Testimony before the Pennsylvania Public Utilities Commission on behalf of the Environmental Defense Fund in R-2016-2547449. July 21, 2016.

**Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case.** Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

**Evaluation of Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers.** Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

**Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest.** Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

**Duke Energy Ohio Smart Grid Audit and Assessment**. Primary research report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

**SmartGridCity™ Demonstration Project Evaluation Summary.** Primary research report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

## Books

**Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment.** Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

## Noteworthy Publications

**The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement.** With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

**Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers.** Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

**Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders.** Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

**Measuring Distribution Performance? Benchmarking Warrants Your Attention.** With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

**Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked.** With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

**Price Cap Electric Ratemaking: Does it Merit Consideration?** With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

**Integrated Distribution Planning: An Idea Whose Time has Come.** Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3rd Ed, March, 2015

**Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs.** Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

**Is This the Future? Simple Methods for Smart Grid Regulation**. Smart Grid News. October 2, 2014.

**A Better Way to Recover Smart Grid Costs**. Smart Grid News. September 3, 2014.

**Smart Grid Regulation: Why Should We Switch to Performance-based Compensation?** Smart Grid News. August 15, 2014.

**The True Cost of Smart Grid Capabilities**. Intelligent Utility. June 30, 2014.

**Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments.** Public Utilities Fortnightly. January, 2012.

**Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments.** Public Utilities Fortnightly. December, 2009.

## Notable Presentations

**National Council on Electricity Policy Annual Meeting.** Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

**NASUCA Annual Meeting.** *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

**Illinois Commerce Commission, NextGrid Working Group 7.** *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

**NARUC Committee on Electricity.** *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

**Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2.** *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

**NASUCA Mid-Year Meeting.** *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

**NARUC Committee on Energy Resources and the Environment.** *How big data can lead to better decisions for utilities, customers, and regulators***.** Washington DC. February 15, 2016.

**National Conference of Regulatory Attorneys 2014 Annual Meeting**. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

**NASUCA 2013 Annual Conference**. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

**NARUC Subcommittee on Energy Resources and the Environment**. *The Distributed Generation (R)Evolution.* Orlando, FL. November 17, 2013.

**IEEE Power and Energy Society, ISGT 2013**. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

**Great Lakes Smart Grid Symposium.** *What Smart Grid Deployment Evaluations are Telling Us*. Chicago. September 26, 2012.

**Mid-Atlantic Distributed Resource Initiative**. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

**DistribuTECH 2012**. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

**DistribuTECH 2012**. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

**NARUC Subcommittee on Electricity**. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators*. St. Louis, MO. November 13, 2011.

**Canadian Electric Institute 2013 Annual Distribution Conference**. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

## Teaching

**Post-graduate Adjunct Professor**. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

**Guest Lecturer**. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

## Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

## Certifications

New Product Development Professional. Product Development and Management Association. 2007.

# APPENDIX B

# APPENDIX B – CARRYING CHARGE CALCULATIONS

## AMI meters and infrastructure

| ASSUMPTIONS | Year 1 | Year 2 | Year 3 |
|---|---|---|---|
| Investment: | 4,553.6 | 6,545.1 | 5,446.0 |
| Debt Ratio: | 50.3% | 50.3% | 50.3% |
| WACC: | 5.89% | 5.89% | 5.89% |
| Authorized ROE: | 9.6% | 9.6% | 9.6% |
| Income Tax Rate: | 30% | 30% | 30% |

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | | Total RR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RR on Year 1 capital | 645 | 624 | 603 | 582 | 562 | 541 | 520 | 499 | 478 | 457 | 436 | 415 | 395 | 374 | 353 | 332 | 311 | 290 | 269 | 249 | | 8,936 |
| RR on Year 2 capital | - | 927 | 897 | 867 | 837 | 807 | 777 | 747 | 717 | 687 | 657 | 627 | 597 | 567 | 537 | 507 | 477 | 447 | 417 | 387 | | 12,487 |
| RR on Year 3 capital | - | - | 771 | 746 | 722 | 697 | 672 | 647 | 622 | 597 | 572 | 547 | 522 | 497 | 472 | 447 | 422 | 397 | 372 | 347 | | 10,067 |
| RR on capital | 645 | 1,551 | 2,272 | 2,196 | 2,120 | 2,044 | 1,969 | 1,893 | 1,817 | 1,741 | 1,665 | 1,590 | 1,514 | 1,438 | 1,362 | 1,286 | 1,210 | 1,135 | 1,059 | 983 | - | 31,490 |
| | | | | | | | | | | | | | | | | | | | Less: Invested Capital | | | 16,545 |
| | | | | | | | | | | | | | | | | | | | Carrying Charges (Total RR - capital) | | | 14,945 |

## Legacy Meters

| ASSUMPTIONS | Year 1 | Year 2 | Year 3 |
|---|---|---|---|
| Investment: | 1,000.0 | 2,100.0 | 2,100.0 |
| Debt Ratio: | 50.3% | 50.3% | 50.3% |
| WACC: | 5.89% | 5.89% | 5.89% |
| Authorized ROE: | 9.6% | 9.6% | 9.6% |
| Income Tax Rate: | 30% | 30% | 30% |

Legacy Meter Revenue Requirement/Carrying Charge Calculation

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | | Total RR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year 1 RR | 158 | 152 | 146 | 140 | 134 | 128 | 122 | 116 | 109 | 103 | 97 | 91 | 85 | 79 | 73 | 0 | 0 | 0 | 0 | 0 | | 1,733 |
| Year 2 RR | - | 332 | 320 | 307 | 294 | 281 | 268 | 255 | 243 | 230 | 217 | 204 | 191 | 178 | 166 | 153 | - | - | - | - | | 3,640 |
| Year 3 RR | - | - | 332 | 320 | 307 | 294 | 281 | 268 | 255 | 243 | 230 | 217 | 204 | 191 | 178 | 166 | 153 | - | - | - | | 3,640 |
| Total RR | 158 | 485 | 798 | 766 | 735 | 703 | 671 | 639 | 608 | 576 | 544 | 512 | 480 | 449 | 417 | 318 | 153 | 0 | 0 | 0 | | 9,013 |
| | | | | | | | | | | | | | | | | | | | Less: Invested capital | | | 5,200 |
| | | | | | | | | | | | | | | | | | | | Carrying Charges | | | 3,813 |

# APPENDIX C

# APPENDIX C – BENEFIT CALCULATIONS

## Meter Reading

| Assumptions | 20-yr TOTAL | Year 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Annual escalation rate | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| AMI deployment rate | | 10% | 60% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | |
| Benefit Estimated by RECO | 41,903,778 | 364,207 | 1,114,044 | 1,892,446 | 1,928,153 | 1,963,859 | 2,003,136 | 2,043,199 | 2,084,063 | 2,125,744 | 2,168,259 | 2,211,624 | 2,255,857 | 2,300,974 | 2,346,993 | 2,393,933 | 2,441,812 | 2,490,648 | 2,540,461 | 2,591,270 | 2,643,096 |
| Benefit Estimated by DRC Expert | 23,677,946 | 102,995 | 630,331 | 1,071,562 | 1,092,993 | 1,114,853 | 1,137,150 | 1,159,893 | 1,183,091 | 1,206,753 | 1,230,888 | 1,255,506 | 1,280,616 | 1,306,228 | 1,332,353 | 1,359,000 | 1,386,180 | 1,413,903 | 1,442,181 | 1,471,025 | 1,500,445 |
| Benefit Reduction | 18,225,832 | 261,211 | 483,713 | 820,884 | 835,159 | 849,006 | 865,986 | 883,306 | 900,972 | 918,991 | 937,371 | 956,119 | 975,241 | 994,746 | 1,014,641 | 1,034,934 | 1,055,632 | 1,076,745 | 1,098,280 | 1,120,245 | 1,142,650 |

## Meter Operations

| Assumptions | 20-yr TOTAL | Year 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Annual escalation rate | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| AMI deployment rate | | 10% | 60% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | |
| Benefit Estimated by RECO | 11,556,706 | 100,445 | 307,244 | 521,921 | 531,768 | 541,616 | 552,448 | 563,497 | 574,767 | 586,262 | 597,987 | 609,947 | 622,146 | 634,589 | 647,281 | 660,226 | 673,431 | 686,900 | 700,638 | 714,650 | 728,943 |
| Benefit Estimated by DRC Expert | 1,629,304 | 7,087 | 43,374 | 73,735 | 75,210 | 76,714 | 78,248 | 79,813 | 81,410 | 83,038 | 84,699 | 86,393 | 88,120 | 89,883 | 91,681 | 93,514 | 95,384 | 97,292 | 99,238 | 101,223 | 103,247 |
| Benefit Reduction | 9,927,402 | 93,358 | 263,870 | 448,185 | 456,558 | 464,901 | 474,199 | 483,683 | 493,357 | 503,224 | 513,289 | 523,555 | 534,026 | 544,706 | 555,600 | 566,712 | 578,047 | 589,607 | 601,400 | 613,428 | 625,696 |

## Avoided Meter Capital

| Assumptions | 20-yr TOTAL | Year 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Annual escalation rate | | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |
| AMI deployment rate | | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | |
| Benefit Estimated by RECO | 6,868,045 | 360,000 | 358,200 | 356,409 | 354,627 | 352,854 | 351,090 | 349,334 | 347,587 | 345,849 | 344,120 | 342,400 | 340,688 | 338,984 | 337,289 | 335,603 | 333,925 | 332,255 | 330,594 | 328,941 | 327,296 |
| Benefit Estimated by DRC Expert | 1,221,649 | 49,333 | 51,326 | 52,353 | 53,400 | 54,468 | 55,557 | 56,668 | 57,801 | 58,958 | 60,137 | 61,339 | 62,566 | 63,817 | 65,094 | 66,396 | 67,724 | 69,078 | 70,460 | 71,869 | 73,306 |
| Benefit Reduction | 5,646,397 | 310,667 | 306,874 | 304,056 | 301,227 | 298,386 | 295,533 | 292,666 | 289,786 | 286,892 | 283,984 | 281,060 | 278,121 | 275,167 | 272,195 | 269,207 | 266,201 | 263,177 | 260,134 | 257,072 | 253,990 |